PETROLEUM PRODUCTION ENGINEERING

OIL FIELD DEVELOPMENT

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BY

LESTER CHARLES UREN

Professor of Petroleum Engineering
University of California

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PREFACE

While the petroleum industry owes its present state of technical development largely to economic geologists and to representatives of the mining, civil, mechanical, electrical and chemical engineering professions, it is generally recognized that a collegiate curriculum in any one of these primary branches of engineering leaves the training of the engineer deficient in one phase or another of the technology of petroleum production. With the purpose of preparing engineering students for participation in all phases of the petroleum industry, a number of universities and engineering schools have organized specialized curricula in petroleum engineering, comprising groups of selected courses extending over four or more years. Wherever introduced, the movement has met with popular response on the part of students and of engineers and others interested in the development of the petroleum industry. This industry promises to require the continued services of many engineers trained both academically and practically to a proper understanding of its specialized problems.

The author's principal purpose in preparing this book and its companion volume, entitled "Petroleum Production Methods," has been to provide a text or work of primary reference for petroleum-engineering students in that part of their curriculum which pertains to the technology of oil field development and petroleum production. The manner of presentation of the data closely follows that developed by the author in eighteen years' experience in the conduct of petroleum production engineering courses in the University of California.

The literature of this field is abundant but widely scattered, much of the best material being unobtainable to one lacking the facilities of a comprehensive library. In the present work, an effort has been made to bring together the more important information relating to each phase of the oil-producing industry and to interpret the major facts in terms of the requirements of individuals interested in the whole rather than in the special subdivisions thereof.

The first edition of "Petroleum Production Engineering" appeared as a single volume in 1924. During the ten years that have elapsed since that time, the technology of oil production has made notable advances, necessitating a broad revision and considerable expansion in the preparation of this, the second edition. Many students of the industry will agree that as much has been added to the permanent literature of this field during this ten-year period as had been contributed during all

previous time. New methods of oil finding have been developed. Wells are being drilled today to depths far greater than would have been possible with the equipment of 1924. Important advances have been made in our understanding of the principles of oil field development and of conditions influencing the drainage of petroleum from its reservoir rocks. New methods of production control have come into vogue that promise to revolutionize the earlier competitive practices upon which the industry of ten years ago was founded. More efficient oil-lifting methods and equipment have been devised. In short, engineering has entered into the business of oil production during the last decade to such an extent as to render almost obsolete the methods and equipment of earlier periods.

So extensive has been the advance in oil production technology that it no longer seems possible to treat the subject in a single volume with the degree of detail required by the engineering student. Accordingly, the second edition of "Petroleum Production Engineering" is offered in two volumes. The present volume, entitled "Oil Field Development," sketches briefly the problems of petroleum exploration, discusses the principles and practices of field development and describes the methods and equipment used in modern deep-well drilling. The companion volume, "Petroleum Production Methods," publication of which is planned to follow closely on completion of the present volume, will deal with the principles of drainage, with production practices and equipment and with the closely related subjects of handling and treating crude oil on the producer's property and with storage and transportation of crude petroleum. It is believed that this classification of subject matter is a natural one that will be found to follow closely the plan of instruction in most engineering schools where the subject is taught.

In the compilation of these two volumes, the needs of the petroleum engineering student have been ever uppermost in the mind of the author. Yet, it is hoped that the new plan of the work may make the second edition of "Petroleum Production Engineering" even more serviceable than was the first, as a general reference manual for the oil-company executive and for the engineer of less specialized training.

Detailed acknowledgment of all sources of information drawn upon in the compilation of the data presented in this work would be impossible within the brief space here afforded, but an effort has been made to indicate the more important works of reference by a system of superior figures inserted throughout the text. These figures refer to similarly numbered items in the bibliography given at the end of each chapter. Publications of the U. S. Bureau of Mines, the American Institute of Mining and Metallurgical Engineers and the American Petroleum Institute are especially prolific sources of information, which have been freely drawn upon. The author is also indebted to the many oil-field

tool and equipment manufacturers who have cooperated in supplying illustrative material and detailed information concerning their products. The author is especially grateful to the many oil-company executives and technologists who have freely shared their experience and technical information, much of which is embodied in this work. Above all, the author is indebted to the University of California for the use of research, library and other facilities and for the many opportunities for field observation that have been his privilege by reason of his association with its faculty.

LESTER CHARLES UREN.

UNIVERSITY OF CALIFORNIA,
BERKELEY, CALIFORNIA,
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CONTENTS

OIL FIELD DEVELOPMENT

CHAPTER I

PROPERTIES, OCCURRENCE AND ASSOCIATIONS OF PETROLEUM IN NATURE

The subject matter of petroleum production engineering may logically be divided into two parts: (1) that dealing with oil-field development, and (2) that which relates to petroleum production. Each is properly regarded as a phase of the petroleum engineer's work, for which he must be adequately equipped in his academic and industrial preparation. Each of these two major subdivisions of the petroleum engineer's field of endeavor presents its own specialized problems; each has its own equipment and methods. A closely related technology is that employed in petroleum exploration, but though the engineer has points of contact and interest in this phase of the industry, it is properly entrusted to the petroleum geologist who is necessarily a man of somewhat more specialized training. However, each must know something of the other's work. Many phases of petroleum technology they share in common.

The author bases his present effort on the conceptions outlined in the preceding paragraph. This volume is devoted to the technology of oil-field development. It is designed to be supplemented by a second volume presenting the technology of petroleum production. The present volume includes a detailed discussion of the problems of planning and conducting the field-development program, the drilling of wells and other matters incidental thereto, and traces the story of petroleum production to the point where the wells are ready to produce. The companion volume will resume the story at this stage and carry it to the point where the crude product is turned over to the refiner. These two volumes are thus designed to cover all aspects of field exploitation.

The first three chapters of the present volume might be considered from one point of view as preliminary to its major purpose, but they are none the less essential to a proper understanding of the work of the petroleum production engineer. The engineer must be informed upon the properties of petroleum and its occurrence and associations in nature —the subject matter of Chap. I. In Chap. II, there is interpolated a brief explanation of the methods followed by the exploration geologist. The engineer must have a general knowledge of these methods so that

he may have a proper conception of all that precedes his own contribution and in order that the points of contact between his field and that of the petroleum geologist may be clearly apparent. The geologist and engineer also share in common the subject matter of Chap. III, which deals with the methods of acquiring title to oil-producing land—a matter necessarily closely related to the general subject of oil-field development. If a sharp line of demarcation between the fields of endeavor of the geologist and engineer seems necessary, it is the author's view that the authority of the geologist should be dominant in all reconnaissance and exploration up to the actual drilling of the test well. Thereafter, through all phases of subsequent field development and exploitation, the engineer should have the guiding hand.

PHYSICAL PROPERTIES AND CHEMICAL CONSTITUTION OF PETROLEUM

Varieties and Forms of Petroleum

Petroleum is a mixture of naturally occurring hydrocarbons which may assume either the solid, liquid or gaseous state. These three phases of petroleum are transmutable, one into the other, by the application of moderate changes in temperature and pressure. Some of the constituents of petroleum are solids at ordinary earth temperatures, but the application of heat to produce a slight rise in temperature will cause them to assume liquid form and further heating to the boiling point will convert them into gases and vapors. Other constituents are vapors at ordinary temperatures, but earth pressures naturally developed within the containing rocks will cause them to condense, forming liquids. Relief of this pressure will permit the liquid to vaporize again, providing the temperature does not change. Liquid petroleum may also be converted into the solid or gaseous states by evaporation of the lighter and more volatile fractions, the latter forming gases or vapors, and the heavier fractions forming solids. The solid and gaseous forms are soluble in the liquid forms. Chemical changes, such as oxidation of the liquid petroleum, may also be instrumental in causing solidification.

In nature, all gradations ranging from hard brittle solid forms through soft waxy substances, viscous semisolids, heavy viscous liquids, light volatile liquids of water-like consistency, and heavy vapors, to light, almost uncondensable gases may be found associated in the same deposit. As pressure, temperature and other physical and chemical changes occur, there will be continual readjustment between the different phases of associated hydrocarbons. Filtration of liquid petroleum through clays and other close-grained rocks within the earth may also bring about segregation of different constituents. It seems probable that most mineral waxes are either oxidation products derived from liquid petroleum or residual products resulting from evaporation or segregation of the more

volatile constituents. Gaseous hydrocarbons, which are always associated with liquid petroleum, are in many cases derived directly from the latter by evaporation or natural distillation; or, the two, having a common origin, may accompany each other throughout their subsequent migration and accumulation.

Chemical Composition and Constitution of Petroleum

Chemically, petroleum consists of a mixture of hydrogen and carbon, the ultimate composition usually showing from 11 to 13 per cent of the former and 84 to 87 per cent of the latter. Sulphur, nitrogen and oxygen, the more important impurities, are often present to the extent of 1 per cent and occasionally to 4 per cent or even more. Helium has also been found as a constituent of some natural gases associated with liquid petroleum. While the elemental constitution of petroleum is fairly uniform, the molecular constitution will vary within wide limits. As many as 18 different series of hydrocarbons have been identified in various crude petroleums, with numerous individual representatives of one or more of these series ordinarily present. An examination of Table I will give the reader an idea of the great variety of combinations of hydrogen and carbon that have actually been identified in petroleum. Doubtless there are many more which have not as yet been isolated.

TABLE I.—CHEMICAL CONSTITUTION OF PETROLEUM

Name and group formula of series	Individual hydrocarbon compounds: Name	Individual hydrocarbon compounds: Composition	Form under ordinary conditions	Remarks
Paraffins (C_nH_{2n+2})	1. Methane	CH_4	Gaseous	These hydrocarbons may be further subdivided into a number of isomeric series—the primary, secondary and tertiary paraffins which, with equal percentage composition, differ in physical properties owing to differences of atomic arrangement within the molecules. This series is present in practically all petroleums, but preponderates in oils of "paraffin base," such as those of Pennsylvania. Lighter members of the series, gases and liquids, are those generally associated with asphalt base oils. The gases carry vapors of the liquid forms at all times. Natural gas is composed almost exclusively of the gaseous members of this series. Hydrocarbons of this series contain the highest percentage of hydrogen and are the most stable.
	2. Ethane	C_2H_6	Gaseous	
	3. Propane	C_3H_8	Gaseous	
	4. Butane	C_4H_{10}	Gaseous	
	5. Pentane	C_5H_{12}	Liquid	
	6. Hexane	C_6H_{14}	Liquid	
	7. Heptane	C_7H_{16}	Liquid	
	8. Octane to	C_8H_{18}	Liquid	
	16. Hexadecane	$C_{16}H_{34}$	Liquid	
	18. Octadecane	$C_{18}H_{38}$	Solid	
	20. Eicosane to	$C_{20}H_{42}$	Solid	
	35. Pentatriacontane	$C_{35}H_{72}$	Solid	
Olefines (C_nH_{2n}) Polymethylenes ($(C_nH_{2n})_x$) (Originally called Naphthenes)	Ethylene	C_2H_4	Gaseous	These hydrocarbons are relatively unsaturated and constitute the so-called "open-chain" hydrocarbons. They include several independent series, differing in physical and chemical characteristics although identical in percentage composition. One of these, the olefine series, is relatively unstable. They have been identified in Canadian oils. The polymethylenes are relatively persistent and occur in California and Russian oils. They predominate in most oils of asphalt base.
	Propylene	C_3H_6	Gaseous	
	Butylene	C_4H_8	Gaseous	
	Amylene	C_5H_{10}	Liquid	
	Hexylene	C_6H_{12}	Liquid	
	Eicosylene	$C_{20}H_{40}$	Liquid	
	Cerolene	$C_{27}H_{54}$	Solid	
	Molene	$C_{30}H_{60}$	Solid	
Acetylenes (C_nH_{2n-2})		$C_{12}H_{22}$	$C_{19}H_{36}$	Lower members of this series have not been found in petroleum. Higher members are characteristic of oils from Texas, Louisiana, Ohio and some California fields.
		$C_{14}H_{26}$	$C_{21}H_{40}$	
			$C_{22}H_{42}$	
		$C_{16}H_{30}$	$C_{24}H_{46}$	
Turpenes (C_nH_{2n-4})		$C_{23}H_{42}$		Higher members of this series are found generally in small amounts in all crudes of low specific gravity, particularly in Ohio, Texas and California oils.
		$C_{24}H_{44}$		
		$C_{25}H_{46}$		
Benzenes (C_nH_{2n-6}) (Aromatic Hydrocarbons)	Benzene	C_6H_6		Found in all crude petroleums in small amounts. Particularly in East Indian, Roumanian and California oils.
	Toluene	C_7H_8		
	Xylene	C_8H_{10}		
	Cumene	C_9H_{12}		
	Cymene, etc.	$C_{10}H_{14}$		

Higher Series: The series (C_nH_{2n-8}) and (C_nH_{2n-10}) are rarely found in petroleum but occur in small amounts in heavy California and Russian oils. Naphthalene ($C_{10}H_8$), found in Rangoon, Russian and California oils, is probably the only member of the (C_nH_{2n-12}) series that has been positively identified. In all, 18 series (to C_nH_{2n-32}) have been identified in crude petroleum.

Paraffin- and Asphaltic-"base" Petroleums

The difficulty of classifying petroleums by the chemical constitution of the hydrocarbon compounds present in such complexity has led to the general use of a simpler and less technical classification. A main line of distinction is drawn between what are called "paraffin-base oils" and "asphaltic-base oils." Paraffin oils yield, on reduction to low temperatures, an appreciable proportion of light-colored wax containing chiefly members of the paraffin series. This wax is not readily attacked by acids, or by ether, chloroform, carbon bisulphide or other solvents in which solid hydrocarbons are commonly soluble. Asphaltic oils on slow distillation yield a dark asphaltic residue, usually jet black in color, lustrous and with a well-developed conchoidal fracture. Asphalt thus formed is readily attacked by the stronger acids and dissolves in the above mentioned solvents. Hydrocarbons of the polymethylene (naphthene) series predominate in most asphaltic oils. It must not be assumed that a very distinct line can be drawn between the so-called paraffin and asphaltic oils; the terms are used mainly for convenience in a broad classification. Nearly all asphaltic oils contain traces of solid paraffins and many essentially paraffin oils contain asphaltic products. Some petroleums are apparently of "mixed base," responding to the tests suggested for both paraffin and asphaltic oils in equal degree. Probably the best example of a typical paraffin-base oil is that produced in Pennsylvania. Most California, Mexican and Russian petroleums are of asphaltic base. Certain oils produced in Oklahoma, Texas and Mexico are of the mixed-base type. In nature's laboratory, hydrocarbons of one type may, by chemical readjustments of the hydrocarbon molecule or by interaction with other substances, be converted into hydrocarbons of other types.

Properties of Liquid Petroleum

Commonly, petroleum occurs in the liquid phase, as an oil somewhat lighter and more viscous than water, varying in color from black, through various shades of brown and green, to a light amber; or, in rare instances, it may be almost colorless. It has a distinctive odor, sometimes described as "aromatic," resembling that of gasoline, one of the more volatile constituents. The odor is often disagreeable, particularly if the oil is contaminated with sulphur or nitrogen compounds. Liquid petroleum has a peculiar property of reflecting light, developing bluish or greenish color effects, known as "bloom," which are not in evidence when the liquid is viewed by transmitted light. Liquid petroleum spread in a thin film on a water surface also develops a characteristic iridescence. Table II presents the more important physical characteristics of liquid petroleum.

TABLE II.—PHYSICAL PROPERTIES OF LIQUID PETROLEUM

Property	Remarks
Color	By transmitted light, pale yellow through various shades of red and brown to black. By reflected light, greenish or bluish shades of yellow, red, brown or black.
Refractive index	Measured with Zeiss refractometer, varies from 1.39 to 1.49.
Specific rotatory power.	Measured with Nicol prism, generally ranges between 0° and 1.2°. Occasionally it may rise as high as 3.1°.
Odor	Aromatic; resembling gasoline, coal tar, oil of cedar, pyridine, etc.
Density	Specific gravity ranges between .75 and 1.01; Baumé gravity from 63° to 10°−. Generally ranges between .82 and .96 in specific gravity.*
Coefficient of expansion.	Varies from .00036 to .00096; generally between .00070 and .00085 (coefficients for Fahrenheit temperature scale).
Boiling point	Not constant. For different constituents ranges from 68°C. to upwards of 300°C.
Freezing point	Ranges from 60°F. down to temperatures as low as −50°F. (the latter being the specified freezing point for aviation gasoline).
Flash point	−12°C. to 110°C., using open cup tester on a large group of California oils.
Burning point	2°C. to 155°C., using open cup tester on a large group of California oils.
Calorific power	Varies from 15,350 to 22,000 B.t.u. per pound, or from 8,500 to 11,350 calories per gram. Generally ranges between 18,000 and 19,000 B.t.u. per pound.
Specific heat	Ranges between .40 and .52. Averages about .45 for most crudes.
Latent heat of vaporization.	Ranges between 130 and 160 B.t.u. per pound for most paraffin and methylene hydrocarbons.
Viscosity	2.3 to 1,300 Engler for a large group of California oils at 60°F.
Radioactivity	Some of the lighter petroleums display radioactive power, which is thought to have some significance in determining their origin.

* Two so-called Baumé scales for comparing the densities of liquids lighter than water are recognized, but one endorsed by the American Petroleum Institute is now universally used throughout the American petroleum industry. The A.P.I. scale has the following relation to specific gravity:

$$\text{Specific gravity} = \frac{141.5}{131.5 + \text{degrees A.P.I.}};$$

or conversely,

$$\text{Degrees A.P.I.} = \frac{141.5}{\text{specific gravity}} - 131.5.$$

In oil-density measurements, the temperature of the oil should always be 60°F. If measured at any other temperature, corrections in the observed gravity readings must be made.

Solid Forms of Petroleum

The naturally occurring solid forms of petroleum include the mineral waxes, paraffin and asphalt. Different varieties of these substances have been given such mineralogical names as ozocerite, gilsonite, grahamite, elaterite, alberite, etc. The reader is referred to any of the books on descriptive mineralogy for descriptions of these different varieties of petroleum in solid form.

Composition and Properties of Gaseous Forms of Petroleum

Gaseous forms of petroleum, commonly called "natural gas," consist of mixtures of hydrocarbon gases and vapors, the more important of which are methane, ethane, propane, butane, pentane and hexane, all of the paraffin series (C_nH_{2n+2}). Petroleum gases are colorless and possess a petroleum odor which is occasionally masked by the stronger odor of impurities, such as hydrogen sulphide or sulphur dioxide. The presence of water vapor sometimes gives natural gas a white, fog-like appearance. Table III indicates the composition and properties of a number of typical natural gases.

Table III.—Physical and Chemical Characteristics of Natural Gas

Source of gas	Sp. gr. air = 1	B.t.u. per cu. ft.	CH_4, per cent	Higher* hydrocarbons, per cent	N_2, per cent	CO_2,† per cent
Average Pennsylvania and West Virginia	.624	1,145	80.85	14.00	4.60	.00
Average Ohio and Indiana	.637	1,095	83.60	.30	3.60	.20
Average Kansas	.645	1,100	93.65	.25	4.80	.30
Santa Maria Field, Cal	.810	1,044	62.70	20.20	1.40	15.50
Coalinga Field, Cal	.660	937	88.00	.00	.90	11.10
McKittrick Field, Cal	.850	724	66.20	1.00	2.40	30.40
Sunset Field, Cal	.660	934	87.70	.00	1.80	10.50
Fullerton Field, Cal	.630	1,100	86.70	9.50	2.10	1.70
Kern River Field, Cal	.660	1,047	84.30	8.00	1.20	6.50
Hogshooter Field, Okla	.580	1,004	94.30	.00	4.60	1.10
Hogshooter Field, Okla	.910	1,548	23.60	69.70	1.30	2.50
Titusville, Pa	.990	1,765	6.60	91.10	2.30	.00
Caddo Field, La	.....	.....	95.00	.....	2.56	2.34

* Recorded as ethane (C_2H_6) in most analyses, though in "wet" gases the hydrocarbons present are frequently propane, butane, pentane and hexane.

† Carbon monoxide, oxygen and hydrogen, recorded in many analyses of natural gas, are probably the result either of contamination of the sample with air or of inappropriate methods of analysis. According to *Bull.* 88, U. S. Bur. Mines, they are never present in natural gas. The gaseous members of the olefin series are also unusual. Hydrogen sulphide and sulphur dioxide are frequently present as impurities.

Petroleum Not a Mineral

Since petroleum is a complex substance of varying chemical composition, it is strictly speaking not a mineral. It may be properly designated, however, as a mineral substance or as an aggregation of minerals.

Thermal Properties of Petroleum

All hydrocarbons are inflammable, whether in the solid, liquid or gaseous state, though the solid and heavy, viscous liquid forms are relatively less so, because of the difficulty of securing admixture with the necessary air to support combustion. The gases are frequently explosive, and the lighter, more volatile liquids, surrounded by an inflammable blanket of their own vapor, are readily ignited and will be completely consumed by the resulting flame. The flash point, or that temperature at which inflammable gases are given off, the fire point, or the temperature at which the liquid will burn and the calorific value are thermal properties which enter as important variables in testing petroleum and petroleum products for specific purposes (see Table II).

Distillation Products of Petroleum

Distillation is an important physical process to which petroleum is subjected in refining and in isolating its various components to determine their composition or suitability for different purposes. Since petroleum is a mixture of a large number of substances of varying boiling points, the more volatile constituents of low boiling point are distilled first when heat is applied in the distillation process, and the higher boiling fractions are evolved in succession as their respective boiling points are reached. Natural distillation of petroleum within the earth as a result of high earth temperatures, and variation in the pressure to which it is subjected during natural distillation, may explain in large part the marked differences in physical and chemical characteristics. Because of the difficulty of making chemical analyses of petroleum, it is customary to subject the oil to fractional distillation, reporting as a rough indication of its value for refining purposes, the percentages of distillate obtained between stated boiling points. Table IV will give an idea of the variations of typical crudes in this respect.

ORIGIN OF PETROLEUM

Though many eminent geologists and chemists have investigated and offered theories and experimental evidence in explanation of the origin of petroleum, the matter is still a subject of scientific controversy. Several of these theories seem to offer plausible explanations of the source and

TABLE IV.—DISTILLATION TESTS OF TYPICAL AMERICAN CRUDE PETROLEUMS*

Source of sample	Density in degrees Baumé	Percentage distilling between temperatures specified, degrees centigrade															Carbon residue of residuum
		Atmospheric pressure										40-mm. vacuum lubricating stocks					
		Gasoline							Kerosene								
		Up to 50	50 to 75	75 to 100	100 to 125	125 to 150	150 to 175	175 to 200	200 to 225	225 to 250	250 to 275	Below 200	200 to 225	225 to 250	250 to 275	275 to 300	
Texas, Humble Field	17.8	...	...	...	...	.5	.9	2.3	4.0	6.6	9.6	7.2	8.4	8.1	8.4	5.3	8.0
Texas, West Columbia Field	19.0	...	...	...	...	...	...	1.5	3.3	6.9	9.9	7.0	10.4	8.3	7.1	9.6	9.1
Texas, Spindle Top Field	19.7	...	...	...	...	...	...	1.5	2.2	6.9	11.8	8.6	11.3	8.1	9.1	9.2	9.7
Texas, Goose Creek Field	20.5	...	...	...	...	...	...	1.7	4.5	9.7	15.1	1.9	8.5	7.7	6.0	10.7	6.0
Kentucky, Ragland Pool	25.2	...	...	2.3	1.7	3.0	3.1	2.5	4.0	5.3	6.7	3.3	5.4	5.9	5.7	5.4	17.7
California, Sunset Field	29.5	.1	1.4	2.1	4.4	4.8	4.2	4.5	5.0	5.6	8.2	2.3	6.4	5.5	5.4	6.3	16.4
Ohio, Cow Creek Field	31.7	...	1.1	1.5	3.5	4.0	5.2	4.4	4.7	5.2	6.8	4.5	5.9	6.6	6.0	7.1	6.5
Kansas, Augusta Field	31.9	...	...	1.8	4.5	5.8	6.6	5.5	6.3	6.5	7.7	4.2	6.9	6.3	5.1	5.5	10.2
Illinois, Lawrence County	32.2	...	.8	1.2	3.3	5.5	4.5	5.1	4.5	4.8	5.2	2.7	5.3	5.5	5.2	6.0	10.6
Texas, Corsicana Field	33.7	...	...	...	2.3	4.0	6.0	7.4	7.8	8.5	7.5	6.5	8.2	6.7	6.6	4.9	9.9
Texas, Somerset Field	34.0	1.4	2.1	4.0	6.0	6.1	5.9	5.5	5.3	5.4	5.8	5.1	5.7	5.2	4.1	4.5	11.8
Arkansas, Eldorado Field	34.4	...	...	7.4	7.0	5.3	5.1	4.0	3.6	4.1	5.1	5.4	7.1	5.5	5.3	5.6	11.0
Oklahoma, Osage County	35.5	.6	1.4	3.9	5.8	5.3	6.1	5.0	5.7	6.6	6.8	5.6	5.8	6.6	4.8	6.1	5.3
Indiana, Lima District	35.8	.6	.8	2.8	5.2	4.9	5.9	5.8	4.8	7.0	7.4	4.1	6.1	5.6	5.3	6.8	6.0
Wyoming, Salt Creek Field	36.5	1.8	1.7	4.7	6.2	5.3	5.5	4.1	4.6	5.3	5.8	4.9	5.9	5.6	5.5	5.8	6.1
Texas, Ranger Field	37.0	...	...	5.4	6.8	6.2	6.1	5.7	6.4	6.7	6.6	5.1	7.0	5.6	5.4	4.5	3.9
Ohio, Corning Crude	37.1	.9	1.8	4.1	5.3	5.5	5.4	4.8	5.2	5.5	6.3	4.0	5.7	5.7	4.8	6.3	7.4
Ohio, North Lima	37.7	.8	1.5	4.4	6.0	6.3	6.1	5.9	6.0	6.6	6.6	4.0	5.9	5.3	5.4	5.5	6.2
Pennsylvania, Venango County	38.3	.4	.7	3.7	6.0	5.0	5.0	3.6	3.9	4.9	7.6	5.5	7.0	6.3	5.9	7.1	2.0
Oklahoma, Cushing Field	39.8	1.5	3.3	3.8	8.7	7.2	6.7	6.3	6.2	6.2	5.6	6.0	5.5	4.9	4.7	4.7	6.8
Louisiana, Caddo Field	41.1	...	3.5	3.8	3.8	6.3	9.7	8.1	9.3	7.0	6.1	4.8	6.3	5.3	4.6	5.2	7.3
Pennsylvania, Green County	41.8	1.1	2.1	3.1	5.7	5.2	5.9	5.9	5.8	6.5	6.4	4.0	6.2	6.5	5.4	6.1	1.6
West Virginia, Maryland grade	42.8	3.3	3.7	5.9	8.2	6.8	6.5	5.8	5.6	6.0	6.4	4.6	4.6	4.5	4.6	4.6	1.4
Pennsylvania, Eureka grade	43.7	2.6	2.9	5.0	7.9	6.9	7.0	5.4	5.6	5.6	6.5	3.6	5.6	4.8	4.8	6.0	2.4

* Tests were made by the U. S. Bureau of Mines—Hempel method in each case. Values for carbon residue of the residuum (last column) are made with the Conradson apparatus and are thought to be indicative of the nature of the oil, *i.e.*, whether paraffin or asphaltic base; and particularly, of its value as a source of heavy lubricants.

Data from U. S. Bur. Mines, *Bull.* 291 by N. A. C. Smith and E. C. Lane.

manner of formation of specific deposits, but apparently none are susceptible of general application.

The various theories that appear in the literature of this subject are usually classified into two groups: the so-called inorganic and organic theories. The former attempt to explain the formation of petroleum as a result of geochemical reactions between water or carbon dioxide and various inorganic substances, such as carbides and carbonates of the metals. The organic theories assume that petroleum is a decomposition product of vegetable and animal organisms that existed within certain periods of geologic time. Table V presents the principal ideas on which a number of the better known theories of each group are based.[1*]

Inorganic Theories Discredited

The inorganic theories, formerly given popular credence, have in recent years given way to theories based on organic evidence, organic origin being now generally accepted. A number of facts have been responsible for the general discrediting of the inorganic theories. Petroleum is notably absent in the rocks formed during geologic periods in which vulcanism was most active. No one has been able to produce it synthetically. Furthermore, the inorganic compounds assumed to be responsible for its formation are rare in nature.

Organic Theories Plausible

In the case of the organic theories on the other hand, there is abundant corroborative evidence, both in nature and from the laboratory, that petroleum may be derived from organic materials of either animal or vegetable origin. Petroleum deposits are in some instances found in close relation with coal deposits of known vegetable origin. In other cases, fish, diatoms, foraminifera, algae and other marine organisms have evidently been the source of petroleum.[10] Carbonaceous shales and sandstones are of widespread occurrence in petroliferous areas and frequently contain sufficient organic material to account for the formation of large deposits of petroleum. The conversion of such organic materials into petroleum has been demonstrated in the laboratory and has been proved possible under conditions normally prevailing in nature.

It seems probable that transformation of the parent organic material into petroleum has proceeded, in the absence of air, in muds, shales and sands along the bottom of shallow lagoons, estuaries, bays and lakes. It has also been suggested that salt water and certain anaërobic bacteria may be essential to the transformation, the former preventing rapid decomposition of the parent material during the transition stage and the latter converting the waxy, fatty and resinous constituents of animal and

* Superior numerals refer to items in the Selected Bibliographies which appear at the end of each chapter.

TABLE V.—THEORIES ADVANCED IN EXPLANATION OF THE ORIGIN OF PETROLEUM

Name of theory or its originator	Salient features	Evidence
Inorganic Theories		
Berthelot's alkaline carbide theory.	Deep-seated deposits of alkaline metals in the free state react with CO_2 at high temperatures, forming alkaline carbides. These, on contact with water, liberate acetylene which, through subsequent processes of polymerization and condensation, forms petroleum.	Evidence lacking. Neither free alkaline metals nor carbides found in nature.
Mendeleef's carbide theory...	Iron carbides within the earth, on contact with percolating waters, form acetylene which escapes through fissures to overlying porous rocks and there condenses.	See above. Magnetic iron oxides would also be formed as a product of these reactions. Magnetic irregularities have been noted in the vicinity of some oil fields.
Moissan's volcanic theory....	Moissan suggests that volcanic explosions may be caused by the action of water on subterranean carbides.	Small quantities of petroleum noted in volcanic lavas near Etna and in Japan. Petroleum also associated with volcanic rocks in Mexico and Java.
Sokolov's cosmic theory......	Petroleum considered to be an original product resulting from the combination of carbon and hydrogen in the cosmic mass during the consolidation of the earth.	Small quantities of hydrocarbon occasionally found in meteorites.
Limestone, gypsum and hot water theory.	Reactions between carbonate and sulphate of lime in the presence of water, at temperatures sufficient to dissociate the water, theoretically may form hydrocarbons.	Practically, it has been found impossible to demonstrate this reaction in the laboratory.
Organic Theories		
Engler's animal origin theory.	Petroleum formed by a process of putrefaction of animal remains. Nitrogen thus eliminated and residual fats converted by earth heat and pressure into petroleum. Activity of anaërobic bacteria thought to play a part in the reactions.	Oils resembling petroleum may be distilled from sediments containing fish remains. Many petroleum deposits associated with marine sediments contain an abundance of foraminifera.
Höfer's vegetable origin theory.	Petroleum formed by decay of accumulated vegetable refuse under conditions which prevent oxidation and evaporation of the liquid products formed.	Deposits of petroleum found in close association with sedimentary deposits containing diatoms, seaweed, peat, lignite, coal and oil shale of known vegetable origin. Oils closely resembling petroleum may be distilled from these substances.
Hydrogenation of coal or other carbonaceous materials.	Solid organic materials converted into liquid hydrocarbons by combination with free hydrogen at high pressures and temperatures in the presence of a suitable catalyzer such as nickel.	Hydrogenation of coal in the laboratory and in commercial plants. The ash of some petroleums is chiefly nickel. However, the existence of free hydrogen in nature is yet to be demonstrated.

plant organisms into hydrocarbons.[9] Various nitrogen and sulphur compounds often found in association with petroleum are considered products of these same biochemical reactions. Temperature and pressure are undoubtedly important physical variables which influence the character of the decomposition products. Possibly in some cases petroleum is formed by actual distillation, in porous formations within the earth, of solid hydrocarbons derived from the parent organic material.

Natural Distillation of Petroleum from Solid Carbonaceous Materials

It seems reasonable to assume that the liquid and solid hydrocarbons have been in many cases subjected to earth temperatures sufficiently high to bring about their vaporization. Some theories assume that the primary hydrocarbon resulting from decomposition of the parent organic material is a solid, conforming in its general characteristics to the "kerogen" present in oil shales. Just as oil is distilled by artificial means from such shales, so it is thought liquid petroleum may be formed by natural distillation within the containing rocks. Hydrocarbon vapors, thus formed, could migrate much more readily than the liquid forms to structures favorable for their accumulation. On subsequent cooling to lower temperatures the vapor so accumulated would condense, forming liquid petroleum. Variation in heat and pressure conditions during this natural distillation process, as well as differences in the character of the parent organic material, would account for variation in the types of oil produced. The entire process, as outlined, is analogous in every way to that practiced in the modern refinery.

Weight is given to this theory by the field evidence obtained from petroleum deposits found in close association with sedimentary strata containing coal. The oil in such cases is clearly a natural distillation product obtained by metamorphism of the coal, the hydrocarbons being driven off, leaving the coal richer in fixed carbon. It is found, furthermore, that the degree of metamorphism which the coal has suffered is a reliable indication of the presence or absence of oil in the vicinity. White has shown that in those regions in which the coals are but little altered by dynamic influence, and where they have a low fixed-carbon ratio, the oils are heavy and of low grade.* On the other hand, in regions of more advanced alteration, where the coals have a higher fixed-carbon ratio, the oils are correspondingly light and of higher grade. Oil is seldom found in regions where the associated coal deposits contain more than 65 per cent of fixed carbon. Considerable gas and a little oil are found associated with 60 to 65 per cent carbon coals, but most of the oil is found where coals range between 50 and 55 per cent in fixed carbon.

* White, D., Some Relations in Origin between Coal and Petroleum, *Jour. Wash. Acad. Sci.*, vol. 5, no. 6, pp. 189–212, 1915.

ACCUMULATION OF PETROLEUM

It is apparent that whatever the theory accepted in explanation of the origin of petroleum, the oil would originally be widely scattered through the containing rocks. It must subsequently be subjected to an agency which will effect a concentration of these disseminated particles before the formation of a deposit of commercial proportions becomes possible. Since the dimensions of petroleum deposits are relatively small in comparison with the areas over which the small particles of oil were originally formed, it is evident that this "migration" of petroleum may necessitate movements over considerable distances. The rocks in which accumulation occurs are seldom those in which the petroleum was formed, and accumulations are occasionally found in formations stratigraphically unrelated with those containing the parent material.[14]

Natural Forces Which Assist in Bringing About Migration and Accumulation of Petroleum

The forces at work in nature which assist in bringing about migration and accumulation of petroleum include: (1) gas pressure; (2) gravity, in association with the buoyant force of water resulting from difference in density, or the gravity differential between water and petroleum; (3) hydraulic pressure developed by flowing waters in subterranean channels; (4) earth pressure, the result of diastrophism; (5) compaction of sediments; and (6) capillarity which, by reason of differences in surface tension between water and petroleum, results in segregation of the two fluids and concentration of petroleum in the more porous rocks.

Gas Pressure.—It has been stated previously in this chapter that natural gas is a universal accompaniment of liquid petroleum. The "fixed" hydrocarbon gases (principally methane and ethane) are probably formed as a product of the same reactions that are responsible for the formation of liquid petroleum. Furthermore, as we have seen, the liquid hydrocarbons have a high vapor pressure, tending to enclose themselves in an atmosphere of their own vapors. This vapor pressure increases with temperature so that at temperatures readily attainable within the earth's surface, some of the hydrocarbons constituting petroleum may at times exist only in the vapor phase. Even though subsequent condensation of these vapors should occur, large quantities of methane, which is not condensable at ordinary earth temperatures and pressures, will ordinarily be present. Though these hydrocarbon vapors and gases are somewhat soluble in the liquid hydrocarbons, it is evident that the processes involved could easily account for large volumes of free natural gas in close association with deposits of liquid petroleum. The field evidence confirms this reasoning, gas being always in evidence wherever liquid petroleum is produced—frequently under high pressures

and in enormous volumes. Gas pressures as high as 2,500 lb. to the square inch are sometimes recorded. Individual wells drilled into certain "pools" have had initial productions in excess of 100,000,000 cu. ft. per day and have averaged many millions of cubic feet per day for long periods of time. A certain relationship between gas pressure and depth is noted, the formational pressure or "rock pressure" ranging in most instances between 36 and 43 lb. per 100 ft. of depth.[18] This phenomenon is theoretically related to the static pressure of ground water, which averages about 44 lb. per 100 ft. of depth below the level of water in the formation (see p. 346).

Gas moves with freedom through the interstices of porous rocks. It exerts pressure equally in all directions, and in its effort to flow from high-pressure toward low-pressure areas within the earth, liquid petroleum is carried along with it. The liquid petroleum may be carried as films surrounding gas bubbles, or it may be pushed through the rocks in relatively large volumes ahead of the gas. Gas in solution in petroleum reduces its viscosity and thus indirectly assists other natural forces in bringing about its migration. Solubility of gas in petroleum increases directly as the pressure, so that at high pressures very large volumes of gas may thus be held in the liquid phase.

Selective Action of Gravity on Rock Fluids. The Anticlinal Theory.—Below the level of the water table, where temperature and pressure conditions permit, rocks are generally saturated with water. Movement of gas as well as of liquid petroleum is undoubtedly brought about in many instances by the selective action of gravity on the rock fluids. Inundated globules of oil tend to float in water by reason of their lower density and accumulate in the upper horizons of the porous strata to which they have access. Such migration is not necessarily vertically upward, up-dip movement along the under side of an impervious capping often contributing a considerable horizontal component. If we consider the gas pressure and hydrostatic forces at work sufficient to overcome the resistance offered by the rock pores, it is obvious that the oil globules will continue to move up-dip until they are trapped or until they reach the highest point in the stratum in which they are stored.

Unless the oil-containing stratum is covered by an unbroken, impervious cap rock, the oil will escape to overlying formations until it encounters an impervious stratum. The crests of domes and anticlines serve in this way as elevated structural traps in which the oil and gas, under the influence of hydrostatic forces, tend to accumulate (see Fig. 1). Gas, being lighter than oil, will tend to accumulate under the influence of these same forces in the upper levels of the anticlinal trap, while oil will occupy an intermediate zone between the gas and the underlying water. So many oil fields show evidence of anticlinal structure, with the major accumulations invariably found at or near the structural crest, that pros-

pectors for petroleum seek, first of all, areas in which anticlinal structure is in evidence. The "anticlinal theory," embodying the principles just presented, is now universally accepted as the controlling factor in oil accumulation.

Consideration of Fig. 1 will make it clear to the reader that inclination of the strata must have a considerable influence on the effectiveness with which the forces causing migration may operate. The greater the dip of the formation, the more rapidly will translation of the oil and gas be effected, and the more complete will be their separation from water and from each other. Other factors, such as rock porosity, gas pressure

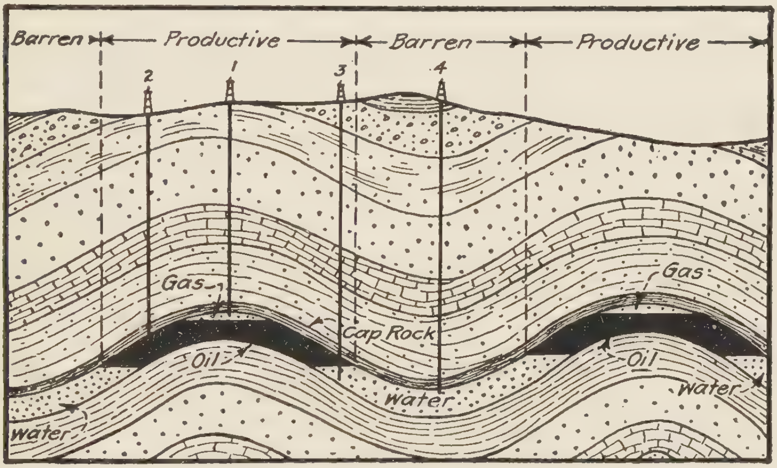


Fig. 1.—Illustrating ideal anticlinal conditions.

The figure shows two productive symmetrical anticlines with intervening barren syncline. Gravitational segregation of gas, oil and water in the anticlinal crests of the oil-bearing stratum has been complete. Well No. 1 is a gas well, but No. 2 is an oil well; No. 3 produces both oil and water; No. 4 is a water well.

and gravity and viscosity of the oil, will also influence the rate of migration and the completeness of separation of the rock fluids.

Migratory Ground Waters. Hydraulic Pressure.—It is definitely known that meteoric waters are often migratory and flow within the earth's surface in well-defined channels. Such movement, while sluggish, due to the resistance to flow which it must overcome, is persistent, and the water may flow in one direction over long periods of time. It is thought that the carrying effect of ground waters in continual motion in this way may be instrumental in transporting globules of oil. We may think of this as due to hydraulic pressure, a force obviously of quite different character from that developed by hydrostatic pressure as described above. Globules of oil flowing in underground water channels may by reason of their lower specific gravity be trapped in anticlinal crests, just as driftwood accumulates in quiet pools along the shore lines of surface streams.

Earth Pressure. Diastrophism.—When sedimentary strata are subjected to forces which bring about the formation of anticlinal and synclinal folds, great differences in pressure within the deformed strata must result. The inner portion of a fold is subjected to compression, the outer to tension. Both result in shrinkage of pore space and expulsion of fluids formerly contained within the rock. Diastrophism varies in intensity at different points within the earth's crust, and fluids expelled from rocks in the region of greatest deformity flow toward the areas where folding is less intense and where more moderate pressures prevail. During this expulsion of the rock fluids, water, oil and gas may be forced to migrate and will tend to accumulate in anticlinal crests in much the same manner as in the case of direct hydraulic pressure.

Compaction of Sediments.—Aside from diastrophism, earth pressure finds expression in another way through the application of direct weight of superimposed sediments. When a stratum of shale, clay or sand is laid down under water, its percentage porosity is high, but as additional strata are superimposed, their weight operates to compact the mineral particles, reducing the pore space between and thus expelling a portion of the contained fluids.[17] Compaction of a shale in this way may result in a reduction of porosity from upward of 80 per cent to but a few per cent of the volume of the rock; hence, large volumes of fluid may be squeezed out and forced to migrate to regions of lower pressure or to "dry" or partially saturated rocks of greater porosity. Oil may thus be largely expelled from a shale source rock and forced to migrate to a suitable reservoir rock.

Capillarity.—Water has a surface tension about 2½ times that of petroleum; therefore capillarity is proportionately effective in its lifting power. The openings in rocks are, for the most part, of capillary size, and through capillary attraction they exert a selective action on the two fluids, drawing water into close-grained rocks and displacing petroleum which is forced into rocks having larger pore spaces. While it would appear difficult to explain the extensive migrations of petroleum that have occurred in some instances as due to the operation of differential capillarity, it seems reasonable to assume that this force may be instrumental in effecting local segregations of water and oil. Lenticular segregation of oil in sands may be explained on this basis, and capillarity may assist in forcing petroleum out of the rocks in which it is formed, into more permeable rocks, where gas, hydrostatic, hydraulic and earth pressure may be effective in bringing about the major concentrations.

LITHOLOGICAL CHARACTER OF PETROLEUM-BEARING ROCKS AND ASSOCIATED ROCKS

A knowledge of the lithological characteristics of sedimentary rocks will be of value to the prospector in studying both the oil reservoir rocks and the enclosing cap rocks. The first essential condition in the

formation of a commercially important deposit is that there must be a porous, fractured, cavernous or creviced stratum in which the oil may accumulate and that this be overlain by an impervious cap rock which prevents escape of the oil after its concentration has been effected.[24]

Oil Reservoir Rocks

Significance of Porosity.—Reservoir rocks are usually sands or sandstones, often loosely cemented so that the percentage of voids may range as high as 37 per cent. The average sandstone has a porosity of about 16 per cent. Many oil-producing sands range between 20 and 25 per cent in porosity. Conglomerates, if not too thoroughly cemented, may have porosities as great as sandstones. Dolomitic limestones have porosities as high as 12 per cent, due to replacement of lime with magnesia, and in certain regions serve as important reservoir rocks for the storage of petroleum.[23] Cleavage planes and solution cavities may increase the storage capacity of limestone to as much as 35 per cent. Even close-grained shales with porosities ranging from 2 to 10 per cent have proved commercially profitable as sources of oil in some fields. However, the presence of clay or shale in an oil-bearing rock must, in general, greatly reduce its storage capacity, the argillaceous material filling in between the coarser constituents of sandstone or conglomerate. Cementation is even more effective in reducing porosity. Obviously, the storage capacity of a porous stratum increases directly with its thickness.

High porosity in a granular rock results from uniformity in size and shape of grains and is independent of the actual size of grain. The arrangement of grains is also an important factor in determining porosity. A sandstone made up of uniform 200-mesh spherical grains has as high a porosity as a similar one of 20-mesh grains. It can be demonstrated mathematically that true spheres of uniform size, packed as closely as possible, have a porosity of 25.95 per cent. If rock particles are spherical but of assorted sizes and closely packed, the porosity will be less than this. Only when the granular particles are of irregular or angular shape may the porosity be greater than 26 per cent.

Of course, sand grains are never truly spherical in form but present an almost infinite variety of sizes and shapes. Being laid down under water in the course of sedimentation, the pore space is generally reduced to the minimum possible value in so far as arrangement of grains is concerned. The relatively flat sides of the larger angular or subangular grains are fitted together, while smaller grains of assorted sizes largely fill the pore spaces between the larger grains. Actual porosities are thus often much lower than the theoretical values quoted above for spherical grains.

While the size of the grain theoretically does not influence the storage capacity of a granular rock, the size of the pores between the grains will

determine what fluids may enter and will have a marked influence upon the rate of movement of fluids through the rock. Oil is less readily absorbed by rock pores than water and flows with greater resistance. Natural gas, while entering the rock pores more readily than water, may nevertheless be displaced by the latter in a fine-grained sand, owing to capillary action. It seems probable that in very small rock openings, capillarity exerts so powerful a force that the contained fluids are held practically stationary within the rock pores, though differential pressures of the order of hundreds of pounds per square inch may be operative.

Storage capacity is not measured solely by interstitial pore space but is also largely influenced by openings of other types. Joint and cleavage planes, vesicular openings, solution cavities, crevices formed by fracturing and angular cavities in brecciated rock masses often serve for the storage of petroleum. Available space for the accumulation of oil in such rock openings varies widely and is difficult to estimate even though the texture and mineral content of the rock are definitely known.

The minerals present in oil-bearing sands and sandstones are of little significance except as a means of identifying and correlating strata. Quartz, feldspar, chlorite, mica, magnetite, ilmenite, amphibole, monozite and pyrite are common constituents of petroliferous as well as other sandstones.

Impervious Cap Rocks

Cap rocks overlying productive oil reservoir rocks are almost invariably argillaceous rocks—clays, shales, slates or marls. Such rocks, in addition to being impervious to oil, are often pliable and do not fracture readily when bent into anticlinal folds. The thickness of the cap rock is often only a few feet, though it must be sufficient, together with the pressure of the overlying rock masses, to withstand the gas pressure in the underlying oil sand if it is to be effective as an oil retainer.

Physical and Chemical Effects of Associated Rocks on Petroleum

Laboratory investigation has demonstrated that oil filtering through certain types of clays and earths (particularly fuller's earth) undergoes changes in chemical constitution and physical characteristics. Such filtration effects partial decolorization and a certain degree of fractionation. Light-colored, transparent, mobile oils of low specific gravity are thus derived by natural processes from comparatively heavy, viscous and dark-colored crudes. It seems probable also that many of the impurities found in petroleum are accumulated during its migration from scattered points of formation to the reservoir in which it is finally concentrated. Some authorities note an increased percentage of sulphur in the oil in certain regions as it travels farther from the rocks in which it was formed.

GEOLOGICAL STRUCTURES FAVORABLE TO ACCUMULATION OF PETROLEUM

It has been shown that the forces causing migration of petroleum tend to concentrate oil and gas in the upper horizons of folded porous strata, particularly in the crests of anticlines. The prospector is therefore attracted in his search by indications of anticlinal structure in any of its various forms. These include symmetric and asymmetric anticlines, domes, monoclines and terraces. Faults and unconformities are occasionally instrumental in isolating the rock fluids in parts of formations in such a way as to influence the accumulation of petroleum. Lenses of porous rocks in close association with carbonaceous shales offer favorable conditions for oil accumulation. Salt domes and volcanic "necks" have in some fields been responsible for accumulations of petroleum, owing to flexuring of strata into which they are intruded. An endless variety of combinations of these structural features present themselves in the geologic study of a prospective oil field.

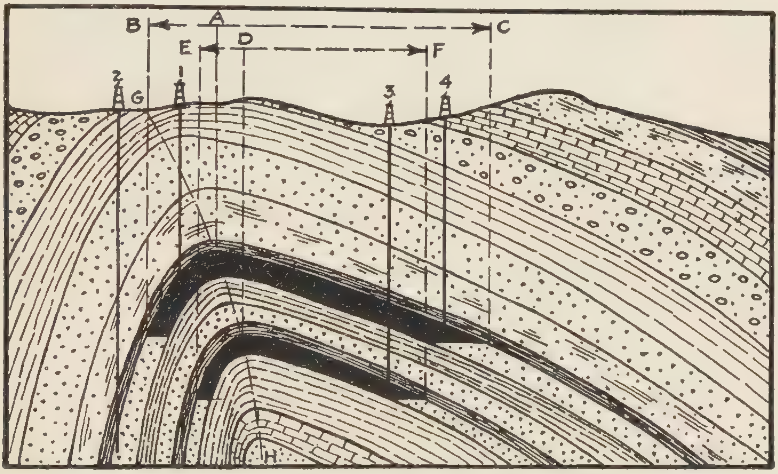


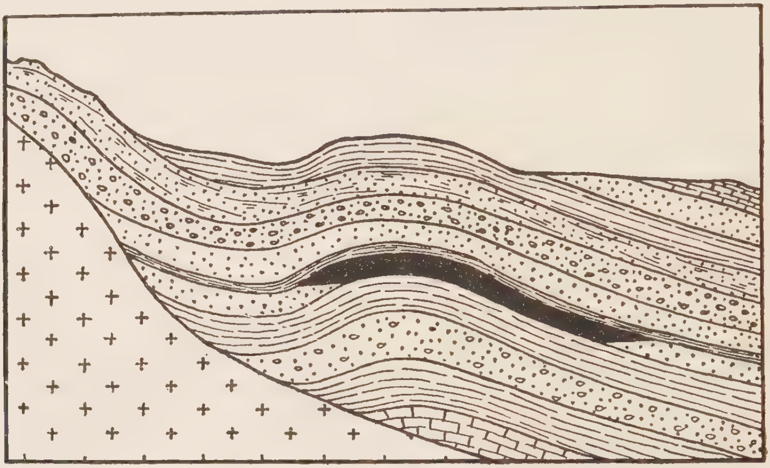
Fig. 2.—Illustrating a simple asymmetric anticline with two oil-bearing strata.

Note change in dip of axis of fold (line *G-H*). *B-C* indicates the width of the productive area for the upper sand, *E-F* that of the lower sand. Axes of folds (at *A* and *D*) lie near the left edge of the productive area. Well No. 1 is productive; No. 2, only a short distance away, is barren. Well No. 4 produces from the upper sand only, No. 3 from both upper and lower sands.

Anticlines

Simple symmetrical anticlines, presenting ideal anticlinal conditions for the accumulations of petroleum (see Fig. 1), are seldom found in nature. Usually one flank is steeper than the other, in which case the more common form of asymmetric anticline results (see Figs. 2, 3, 4 and 5); or the axis of the anticline plunges, *i.e.*, is not level (see Fig. 5). A common type of asymmetric anticline, known as "terrace structure" in certain fields, has one flank nearly vertical and the other inclined at

only a few degrees from the horizontal (see Fig. 4). Overturned folds and intense folding may result in exceedingly complex structures, often difficult to interpret from the field evidence (see Fig. 6).



(*After W. H. Emmons.*)

FIG. 3.—An asymmetric anticlinal fold along the flanks of a major uplift, illustrating how greater accumulations of petroleum may be found on the basinward side of an anticline. Note difference in level of the edge-water lines on opposite flanks of the anticline.

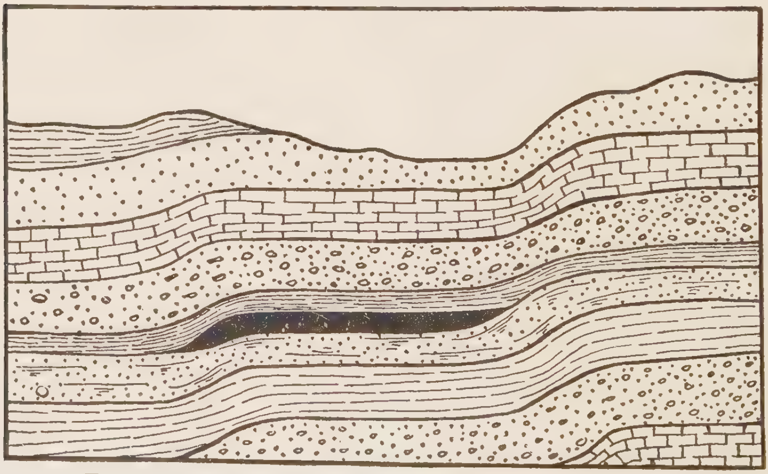
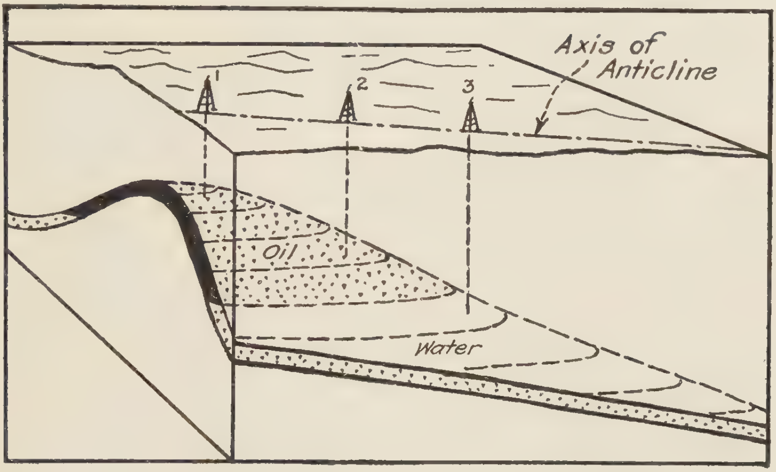


FIG. 4.—Illustrating oil accumulation on "terrace structure."

It must be remembered that the axes of anticlinal folds are seldom straight lines but curve in both the horizontal and vertical planes (see Fig. 8). Where they curve sharply, strata on the inside of the fold are compressed while those on the outside are put under tension, thus forcing the oil toward the outer flank, away from the point of greatest compres-

sion. Especially prolific concentrations of oil may be expected where a change in strike of the axis occurs and especially on the convex side of the fold.



(*After D. Hager.*)

Fig. 5.—Stereogram of a plunging anticline.
Wells Nos. 1 and 2 are productive; No. 3 encounters edge water.

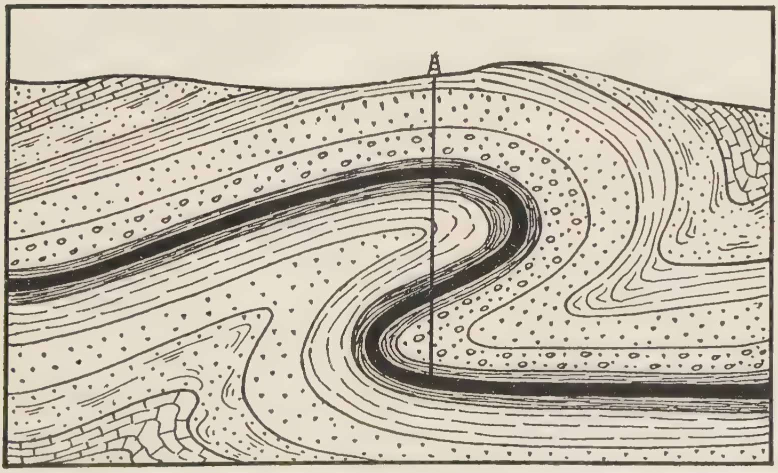


Fig. 6.—An overturned anticlinal fold, showing how one well may intersect the same oil sand three times.

Many anticlinal folds that are productive of oil occur along the lower flanks of major uplifts. The greatest accumulations of oil in such cases are generally found on the basinward flank of the anticline, this side having the advantage of a greater area over which concentration of the oil has been operative (see Fig. 3). In some cases the three

anticlinal zones, occupied by gas, oil and water respectively, will be fairly well developed, with a well-defined "edge-water" line marking the limits of the oil "pool." In other cases, particularly in low-dipping strata, the oil and gas will be intimately associated in all parts of the

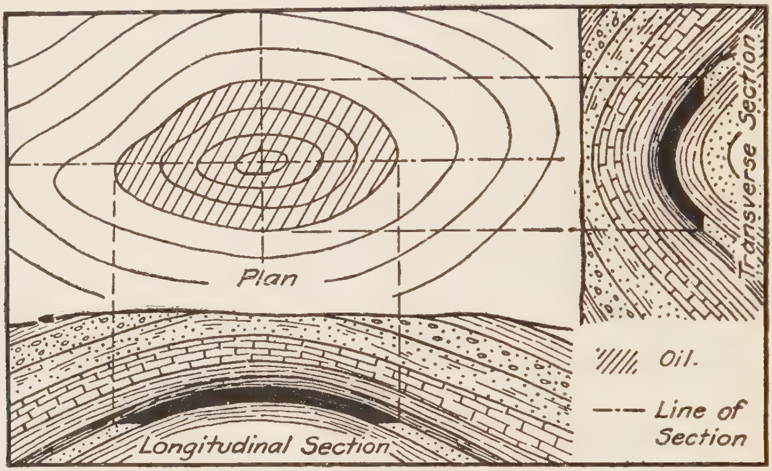


FIG. 7.—Dome structure illustrated in plan view by structure contours and by vertical sections through the major and minor axes.

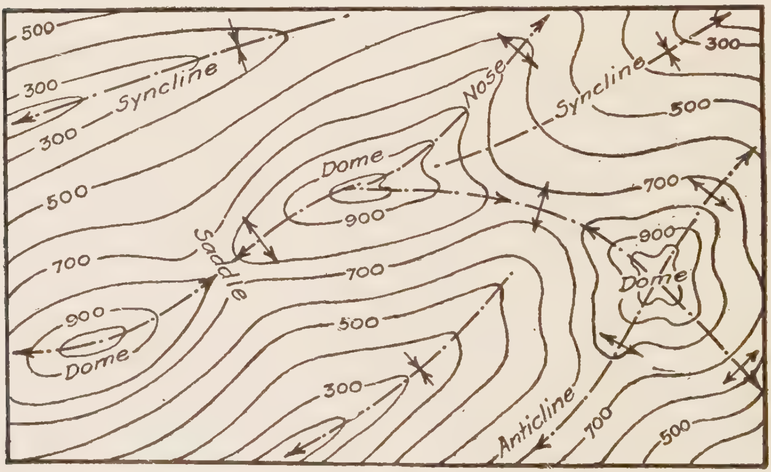


FIG. 8.—Structure contour map showing form of top surface of a producing oil sand and illustrating manner of indicating various structural features.
Oil accumulates under the three domes.

productive zone, and the edges of the pool will produce mixtures of oil and water. The edge-water lines are often at different levels on opposite flanks of an anticline, and may move up- or down-dip at times, with changes in porosity of the containing stratum.

Domes

In the case of domes we have the conditions favoring high concentration of oil and gas best developed. The structure here dips off in all directions from a crestal point, and oil is concentrated from all flanks over the entire area of the dome toward its summit. Many of the most productive oil fields exhibit well-developed dome structure, and in nearly every case the highest concentrations of oil and gas are found at or near the structural crest.

Domes are of various forms (see Figs. 7 and 8). They are the result of two or more intersecting anticlines or of local variations in dip on the flanks of some larger fold. More rarely they are formed by pressure

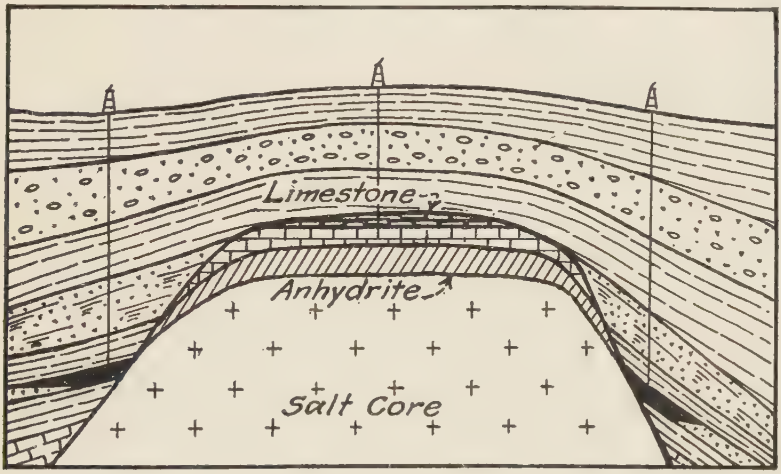


Fig. 9.—A typical salt-dome deposit.
Oil accumulates in porous formations above and on the flanks of the salt core.

from below of intrusive igneous rocks, or as a result of pressure developed by the intrusion of large bodies of salt (salt domes, see Fig. 9). Popular usage does not clearly distinguish between what are sometimes called "elongated domes" and ordinary anticlines. All anticlines are long, narrow domes in the sense that they are closed structures, plunging or flattening out at each end where they merge with other structures. Hager suggests that only closed structures in which the length does not exceed three times the width be spoken of as domes.[16]

Monoclines

When the crest of an anticlinal fold is eroded away, a partial cross section of the strata making up the fold is exposed at the earth's surface and the undisturbed lower flanks form what are called "monoclines" (see Fig. 10). If one or more of the outcropping strata contain oil, the

nature of the material will be made evident by accumulations of oil and bituminous materials along the outcrop. The upward pressure of gas and the hydrostatic head, still operative in the oil-bearing strata, tend to force the oil out of the sands, accumulating it in pools on the earth's surface, from which it evaporates or is carried off by the natural water courses. Wastage of oil, as a result of erosion of anticlinal crests and exposure of oil-bearing strata, has undoubtedly been responsible for the dissipation of much of the petroleum accumulated by nature's processes in former geologic periods. Fortunately, if the deposit is a large one, the oil is capable, by reason of its own physical properties, of sealing the outcrop and preventing escape of the oil originally stored in

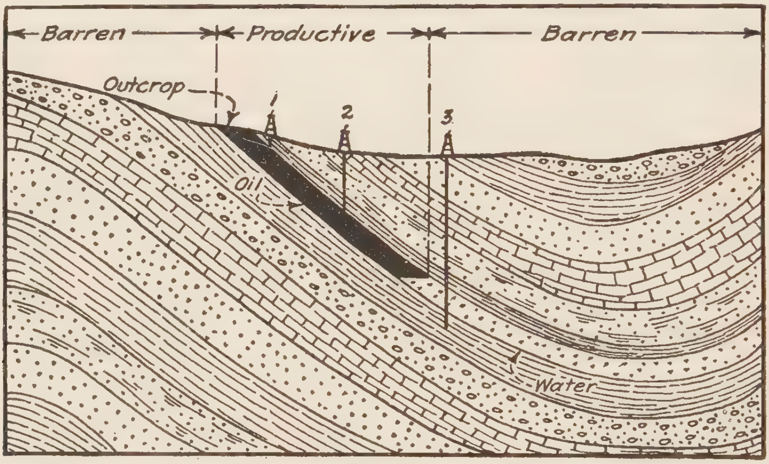


FIG. 10.—Illustrating simple monoclinal structure.

The shallow well, No. 1, produces heavier, more viscous oil than No. 2, due to evaporation of the lighter constituents at the outcrop. Well No. 3 encounters edge water.

the lower flanks of the fold. This is accomplished by evaporation of the lighter and more volatile constituents of the oil, leaving in the surface rocks a residual product of solid paraffin or asphalt which completely closes the rock pores and prevents further migration from below. The remnants of oil deposits, so exposed and yet protected from further loss, are readily located by their prominent bituminous outcrops, are easily developed and serve as important sources of petroleum in some fields.

FAULTS

Faulting, being the result of the same earth forces that bring about folding of strata, is often in evidence in oil-bearing formations and must be considered as a factor in oil accumulations. A fault may intersect an oil deposit and so displace one portion with respect to the other that for all practical purposes they become separate deposits (see Figs. 11, 12

and 13). Faults sometimes fracture a porous monoclinal stratum, formerly barren of oil, and interpose a stratum of impervious clay or shale across the faulted face in such a way that a structural trap is formed

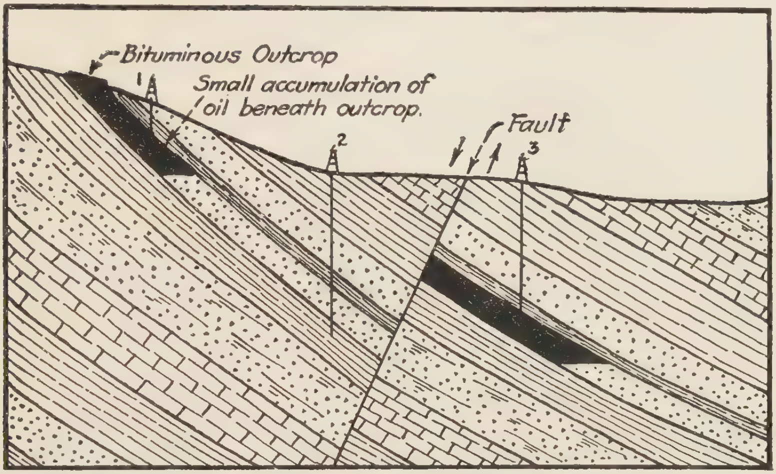


FIG. 11.—A faulted monocline.

The illustration shows how a fault may interpose an impervious stratum across the lower part of an oil-bearing stratum, permitting accumulation of a deposit of petroleum, which is sealed by the fault "gouge" and prevented from escaping up the dip of the structure. Wells Nos. 1 and 3 are productive. Well No. 2, halfway between, encounters edge water.

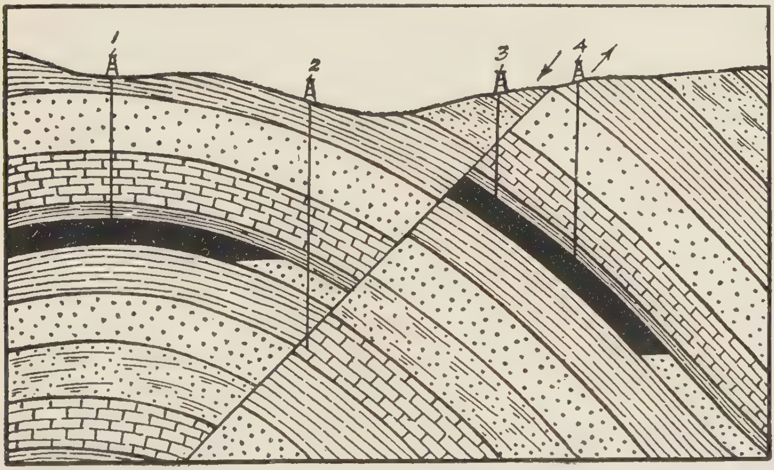


FIG. 12.—A faulted anticlinal arch.

The figure illustrates oil accumulation on both the up-throw and down-throw sides of a fault, and shows how faulting may leave barren places in anticlinal structure. Wells Nos. 1, 3 and 4 are productive; No. 2 encounters edge water; No. 3 intersects the fault plane.

in which oil may subsequently be concentrated. It is commonly supposed that faults provide channels of communication between strata originally separated from each other by impervious beds. Fluids may thus be transferred from stratum to stratum across fault planes, perhaps dissi-

pating accumulations of petroleum through great thicknesses of formerly barren rock (see Fig. 13). While the influence of faults on oil accumulations must always be somewhat problematical, they constitute a disturbing structural feature which the prospector must take into account in locating test wells.

Unconformities

A period of erosion, perhaps accompanied by tilting and folding, may intervene between two periods of deposition, leaving the accumulations of the two periods unconformable at their surface of contact. Strata of the older series may thus dip at entirely different angles from those

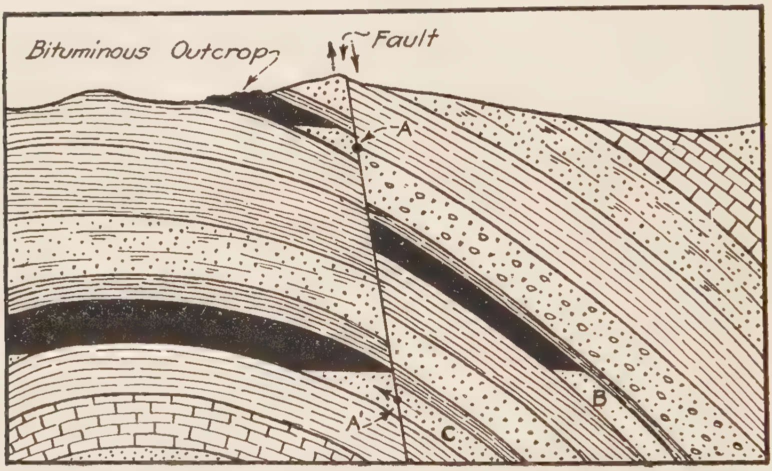


Fig. 13.—A faulted anticlinal arch.

The down-throw side has moved from A to A', dislocating two oil sands, B and C. The up-throw side of B has been eroded away, but a remnant of the up-throw side of C still remains below the bituminous outcrop. Oil from the down-throw side of C has migrated across the fault plane and accumulated in the crest of a porous sand, formerly barren.

of the younger series. Sealing of porous beds of the lower series by impervious layers of clay or shale at the base of the upper series may provide favorable conditions for the accumulation of petroleum in the older rocks against the unconformity (see Fig. 14). In other cases oil originating in the lower formation may flow along and across the unconformity, accumulating in upper strata only remotely related with those in which the oil was originally stored. Compaction of sediments deposited on an eroded surface possessing considerable relief will sometimes result in the younger beds developing dips roughly conformable with the eroded surface of the older formations. Petroleum originating in the younger beds may thus migrate up the dips thus created, accumulating against the flanks of the "buried hills" and ridges of the old erosion surface.[17] Such conditions are exceedingly difficult to decipher in the

field, and surface structural studies will be of little assistance in working out the true situation.

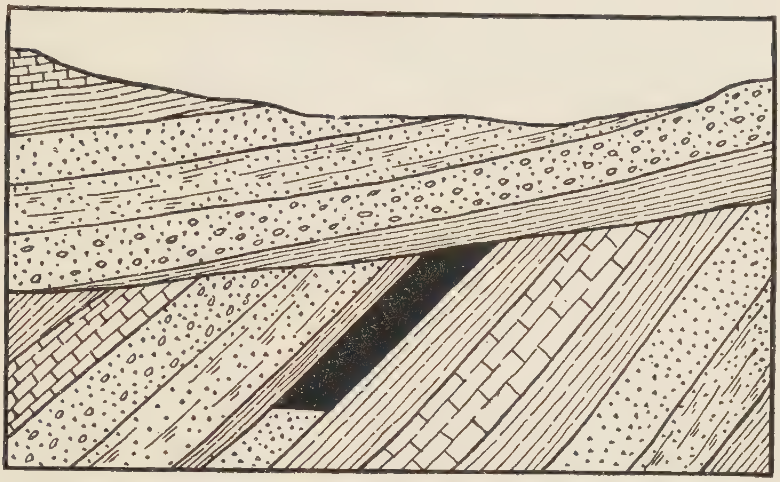


Fig. 14.—Illustrating accumulation of petroleum against an unconformity. The impervious stratum at the base of the upper series prevents escape of the oil.

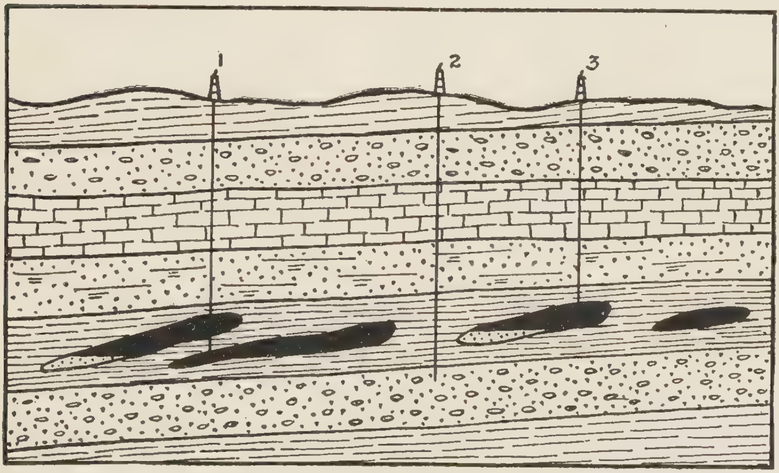


Fig. 15.—Lenticular deposits.

Lenses of coarse sand embedded in oil-bearing shales serve as local centers of concentration. Well No. 1 produces from two lenses, No. 3 from only one. Well No. 2, between No. 1 and No. 3, is unproductive.

Lenticular Deposits

Lateral variation in oil-bearing strata, particularly in sands and sandstones, is often responsible for marked changes in the oil content of strata at different points (see Fig. 15). This is due to variation in character of grain structure, cross-bedding and other irregularities resulting from the

manner of original deposition of the containing rock. The result is a succession of lenses of porous sands embedded in relatively close-grained rocks, the whole forming what is apparently one continuous, fairly well-defined stratum. Oil naturally seeks out the porous lenses in which to accumulate, leaving the less porous rocks comparatively barren. In general, the major concentrations would be influenced by anticlinal structure in such a lenticular stratum, but surprising differences in saturation of the sands will be in evidence. Perhaps the crest of the structure, which would ordinarily be selected as the best site for a test well, will be almost barren, while an apparently less favorable position, with respect to the structural evidence, will be highly productive. Such conditions can scarcely be taken into account in geological surveys for the location of test wells and constitute one of the inherent uncertainties with which the oil prospector must contend.

It has been stated that the original organic material from which petroleum is derived was probably deposited in sedimentary marine strata in shallow waters along the shores of bays and lagoons. Most sedimentary strata are laid down against shore lines, and any cross-bedding that might be developed, as well as any segregation of coarse and fine detritus during deposition, would be roughly parallel with the shore line against which it has been formed. It follows that the lenses or channels of relatively porous sands in which petroleum later accumulates should be approximately parallel to the shore lines of the period in which they were formed. Field evidence shows this to be generally true.[13] The location of ancient shore lines is therefore of assistance to the petroleum prospector in aiding him to predict the probable trend of lenses and channels that are responsible for unequal distribution of petroleum in the containing stratum.

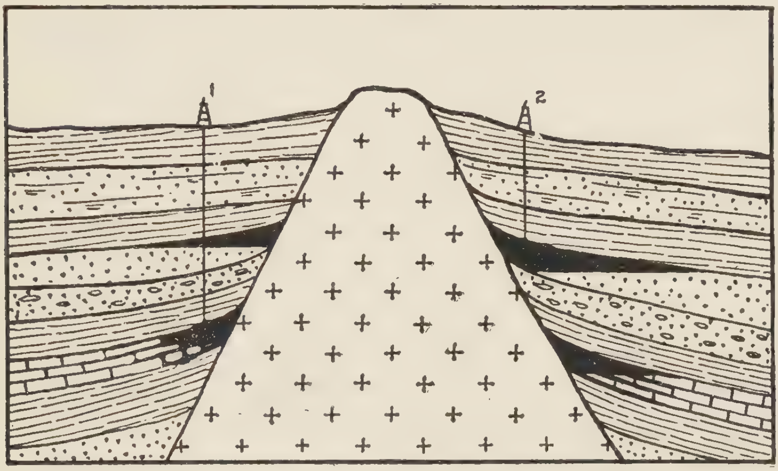
Salt-dome Deposits

In portions of the Gulf Coast region of the United States, in Germany and various other oil-producing regions, petroleum is found in close association with deposits of salt (see Fig. 9). These salt masses are largely anhydrite, but replacement processes often provide the salt mass with a gypsum or dolomite capping.[12] The salt deposits have been responsible during their accumulation for considerable upward pressure, resulting in doming of the overlying sedimentary rocks. It is considered probable that these salt masses were intruded into the sediments in which we now find them, salt flowing as a viscous semisolid when subjected to high pressure. Doming of the sedimentaries has in many cases effected concentration of petroleum originally disseminated through the surrounding formations so that it accumulates within the upturned porous beds about the summit and flanks of the salt core. Upward of a hundred salt domes have been found in the Gulf Coast area of the United States,

and the sedimentaries about them have in many cases been found to be productive of petroleum in commercial quantities.

Petroleum Deposits in Association with Volcanic Intrusions

In certain Mexican fields petroleum is found in sedimentary strata, the edges of which have been folded up along the flanks of volcanic necks (see Fig. 16). Apparently in such cases the intrusive igneous rocks have merely been responsible for the development of folds into which oil has migrated from the surrounding sedimentary formations. Such deposits are rare and do not constitute any exception to the universal derivation of petroleum from sedimentary rocks.



(*After F. G. Clapp.*)

Fig. 16.—Illustrating occurrence of oil on the flanks of an intrusive volcanic neck. Oil accumulates in upturned edges of porous sedimentary rocks. Well No. 1 may produce oil from two horizons, while No. 2, located nearer the intrusive contact, produces only from the upper horizon.

SURFACE INDICATIONS OF PETROLEUM

The attention of the prospector is often attracted by surface indications which have come to be regarded as indicative of the presence of petroleum. These include oil seepages, hydrocarbon gas emanations, bituminous outcrops and deposits of asphalt and paraffin waxes. In addition to these positive indications of petroleum, there are other occurrences which do not necessarily indicate the presence of petroleum but which are often associated with oil deposits. Salt and brine, sulphur and sulphurous waters and gases, acid waters, oil shale and burnt shale are commonly regarded as offering corroborative but not conclusive evidence.

Oil Seepages

Oil seepages offer the most direct evidence of the presence of petroleum. In places where oil-bearing rocks outcrop at the surface, or where

the cap rocks overlying an oil deposit have been fractured, oil may come to the surface as "oil springs" or may accumulate in pools along the outcrop or fault plane. The flow of oil is seldom copious because of the tendency of petroleum to seal such outlets by the accumulation of solid hydrocarbons resulting from evaporation of the lighter liquid constituents. Petroleum escaping in this way, even in minute quantities, will often make its presence known by the formation of iridescent films on water in ponds, wells, springs and streams. This film, which is quite characteristic, somewhat resembles that formed by oxide of iron, but the latter will be readily distinguished by its brittleness. The oil film is cohesive and persistent and displays a peculiar tendency to disperse on the water surface when brought into contact with a little ether vapor or with a drop of ether on the end of a glass stirring rod.

Hydrocarbon Gases and Related Phenomena

Because of their common association in nature, hydrocarbon gases are also significant indications of the presence of petroleum. Cap rocks may be sufficiently impervious to prevent oil seepages from reaching the surface, but the slightest crevice or joint plane will serve for the passage of gas. Hydrocarbon gases, being colorless, are not so conspicuous as oil seepages, but their presence is often made apparent, when associated with oil, by their characteristic petroleum odor. They burn readily and are explosive when mixed with proper proportions of air.

The petroleum odor of hydrocarbon gases associated with oil deposits is often masked by the stronger odor of hydrogen sulphide and sulphur dioxide with which they are sometimes contaminated in nature. The characteristic odor of ammonia is occasionally observed in gases associated with petroleum. Rogers* has suggested that ammonia may be derived from naturally occurring ammonium compounds, such as ammonium sulphate, by contact with hydrocarbons in either the liquid or gaseous phase. Interreaction of the two sulphur gases with water sometimes results in the formation of native sulphur in the form of a sublimate about the openings through which the gases escape. Sulphuric acid similarly formed may give the ground waters of the locality a slight acid reaction. Rogers also suggests that sulphur and sulphur compounds are in many cases derived from sulphates by the reducing action of hydrocarbons. Anaërobic bacteria that may exist in crude petroleum throughout long periods of time have been shown to have the power of converting sulphates into sulphides. Pyrite, though often present in rocks associated with oil and gas, is not considered as an indication of petroleum. The presence of sulphur and sulphur gases cannot be regarded as more than corroborative evidence, since they are often formed

* Rogers, G. S., Chemical Relations of Oil Field Waters in the San Joaquin Valley, California, U. S. Geol. Survey, *Bull.* 653, 1917.

by reactions which are not in any way related to the occurrence of petroleum. Even hydrocarbon gases are not infallible evidence, as "marsh gas," which is chiefly methane, is often found where oil is not. If the gases are "wet," *i.e.*, if they contain ethane, propane, butane or hexane as well as methane, the presence of liquid petroleum in association with the gas is more definitely assured.

When escaping through argillaceous rocks at the earth's surface, gases have a tendency to build up clay mounds about the openings through which they issue. These accumulations, generally in the form of a cone, are called "mud volcanoes." They vary greatly in size from small mounds to hills covering many acres and simulate on a small scale all the characteristics of true volcanic activity. On erosion, the crevices on which the mounds accumulate may become filled with mud, forming mud dikes. Mud volcanoes and mud dikes prominently mark the position of gas "seeps" in some oil fields.

Bituminous Outcrops

When liquid hydrocarbons are subjected to contact with air, evaporation of the lighter constituents leaves a solid residue of asphalt or paraffin wax. Oxidation of the heavier hydrocarbons is also a factor in this process of solidification. The sandstones in which these solid hydrocarbons are deposited become tough and resistant to weathering and disintegration, forming prominent bituminous outcrops where the oil-bearing strata intersect the surface. These bituminous deposits are quite characteristic and in many fields have attracted the attention of prospectors to the particular strata with which they are associated. In some instances deposits of liquid petroleum are found in monoclinal structures a few hundred feet down the dip of the strata below the outcrop. In other cases, bituminous sands are apparently merely remnants of former oil deposits which have been eroded away. In any case, however, they prove in no uncertain manner that the strata in which they occur are petroliferous, and they may serve to focus attention on their particular horizon in anticlinal structures in the vicinity where sealed deposits of petroleum may be found.

If the bituminous material has been subjected to weathering and oxidation, only traces of the petroleum formerly present will be in evidence, occasionally so little that resort must be had to the acetone test or to solution tests with one or another of the various oil solvents to disclose its presence or, a closed-tube distillation test may be applied. In the latter, a little of the dried and powdered material heated to redness in the closed end of a glass tube will yield oil vapor which condenses near the open, cold end of the tube as a yellowish white or brownish "fog" or in small drops. Black manganese oxide often stains a sand or sandstone so that it apparently contains a carbon-like residue, but it is

readily distinguished when the solvent and heat tests are applied. Certain carbonate waters and other aqueous solutions containing in suspension finely divided and concentrated organic residues of vegetable origin, closely resemble petroleum in general appearance but have none of its specific properties.

Mineral Waxes

The mineral waxes, particularly gilsonite, grahamite, albertite and ozocerite, are derived directly from liquid petroleum by segregation of the lighter constituents. They are commonly found in veins or fissures and are often spoken of as "intrusive" petroleum. Such deposits are sometimes directly connected with deposits of liquid petroleum and in any case serve as conclusive evidence of the petroliferous character of the rocks in which they are found. Outcrops of such veins, or even fragments of mineral wax resulting from erosion of wax deposits, are therefore of interest to the prospector for petroleum.

Bituminous Shales

Deposits of bituminous shale containing "kerogen" from which petroleum may be derived by natural processes, though offering no definite assurance that oil is present in association with them, are nevertheless indications that the prospector cannot afford to ignore.* When the raw material from which petroleum may be derived is known to be present in the region, a search for localities in which the conditions are favorable for the necessary metamorphosis and accumulation may result in the location of deposits of liquid petroleum.

Strata containing bituminous shales have in some cases become ignited—perhaps spontaneously—and all or most of the carbonaceous material has been consumed, leaving hard, resistant layers of "burnt shale." Such shales are usually highly colored by red oxide of iron, and, because of their hardness and resistance to weathering, often form the crests of prominent ridges and "tables." Even though they are no longer carbonaceous, the knowledge that they were so at one time may be suggestive to the prospector in searching for localities which might have escaped the destructive agency, or for localities in which hydrocarbon vapors might have condensed forming deposits of petroleum.

Saline Ground Waters

Knowledge of the universal association of salt water with petroleum stimulates interest on the part of the prospector in all brine springs and

* The "pyro-bitumens" do not, as a rule, respond to the solvent tests described above and must be heated before their carbonaceous character becomes evident. A little of the powdered material, heated to redness in a glass tube closed at one end, will yield oil vapors which condense on the walls of the cold end of the tube. The odor of these vapors is quite characteristic.

deposits of salt. Such occurrences, however, are very common in nature and are not necessarily indicative of the presence of petroleum. They are to be regarded at best as nothing more than corroborative evidence to substantiate predictions based on other and more positive indications.

"Paraffin Dirt"

In the vicinity of the salt domes of the Gulf Coast region, the surface soil contains quantities of a yellow, waxy substance resembling paraffin or beeswax, which has been given the name of "paraffin dirt." It is thought by some oil prospectors to be indicative of the presence of petroleum in the vicinity, but many question its supposed intimate relationship. A detailed study of several such occurrences has led to the opinion that it is derived from decomposing vegetable matter in the soil and is not related to the petroleum deposits of the region.

Stunted Vegetation

The effect of petroleum present in surface soil is detrimental to the growth of vegetation. Plant life in such soils is either entirely lacking

Table VI.—Geologic Age of Petroleum Deposits

Era	System	Order of productivity in the U. S.	Type of oil
Quaternary	Recent		Generally unproductive.
	Pleistocene		
Tertiary or Cenozoic	Pliocene		Generally asphaltic base petroleums.
	Miocene	1	
	Oligocene		Tertiary formations produce more than half of the world's petroleum.
	Eocene		
Mesozoic	Cretaceous	3	
	Jurassic		Generally unproductive.
	Triassic		
Paleozoic	Permian		
	Carboniferous	2	Generally paraffin base petroleums.
	Devonian	4	
	Silurian	6	
	Ordovician	5	
	Cambrian	7	
Proterozoic	Keweenawan		Unproductive.
	Amikean		
	Huronian		
Archeozoic	Archean		

or is stunted. So marked is this influence in regions where vegetation is ordinarily prolific that in certain instances attention has been directed to the soil, which on examination has been found to contain traces of

petroleum. Since plant life may be absent for many other reasons than the presence of petroleum in the soil, such an occurrence is of only slight significance.

GEOLOGIC AGE OF PETROLEUM-BEARING ROCKS

Paleontological classification of petroleum occurrences the world over indicates that petroleum is not confined to any definite geologic period, but occurs in rocks ranging in age from the Cambrian to the Recent (see Table VI). While petroleum is thus distributed through a considerable portion of the geologic column, it is found that the more prolific horizons may be located within closer limits. More than half of the world's petroleum has been produced from rocks of Tertiary age.[15] Paleozoic rocks have also been particularly prolific. A broad classification serves to indicate that the bulk of our asphaltic oil comes from rocks younger than the Jurassic.[3] Much of the so-called paraffin-base oil is derived from rocks older than the Permian. Lower Cretaceous, Jurassic, Triassic and Middle and Upper Permian rocks of North America are as yet unproductive.

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CHAPTER II

PETROLEUM EXPLORATION METHODS

Exploration for new supplies of petroleum to replace the ever waning production from known fields is an important phase of the petroleum industry. While often regarded as a separate and distinct activity, petroleum exploration is a subject so closely related with field development that the engineer engaged in oil field work must have general familiarity with its problems and methods. The detailed application of exploration principles and methods is properly entrusted to petroleum geologists specializing in this kind of work, but the petroleum engineer carries on the exploration of oil fields from the point where the geologist stops and each must be in some measure familiar with the methods of the other. Accordingly, this chapter is introduced, not with the purpose of attempting a thoroughgoing dissertation on the subject of petroleum exploration, but rather, such an outline as the production engineer requires in familiariz ng himself in a broad way with the methods by which new oil fields are discovered.

GEOLOGY THE PRINCIPAL KEY TO OUR UNDISCOVERED OIL RESOURCES

In the previous chapter, it has been shown that petroleum is found only where geologic structure is favorable, and that it is confined for the most part to definite horizons and certain types of rocks. Accordingly, the principal effort of the petroleum exploration geologist is directed toward the identification of structure and lithology in geologic horizons and formations known to be promising. Petroleum is apparently found only in sedimentary formations younger than those formed during Proterozoic time and, for the most part, within the Tertiary and Paleozoic eras of the earth's history. The geologist therefore gives particular attention to areas in which formations representative of these periods are to be found within reach of the drill. In such areas he seeks to discover a source rock which may conceivably have furnished an organic parent material. His interest then attaches to any related porous formations, suitably capped, which might serve as a reservoir rock. If then an area can be found in which these formations are suitably folded into anticlinal forms, favorable conditions for the accumulation of petroleum are disclosed. It is also the task of the geologist to indicate the acreage within the favorable area which would probably be most valuable from a development and production standpoint and to select the positions for such test wells as will be necessary to determine whether or not commercial production of petroleum may be realized.

Regional Reconnaissance

The geologist is often attracted to particular localities by reports of surface indications of the presence of petroleum, such as have been described in Chap. I. These will prove the presence of petroleum in rocks of a particular horizon; however, they do not necessarily indicate the presence of oil in commercial amounts. They may be remnants of some earlier deposit, the major part of which has been dissipated by erosion and degradation of the structure in which they were originally stored. Conditions in the locality may never have been favorable for an accumulation of commercial proportions, and such surface signs as are in evidence may merely be the result of small local concentrations. A well-defined anticlinal or domal structure in the locality of such an occurrence, however, would doubtless be of great interest to the geologist.

Most of the significant surface occurrences in the more accessible regions have already been investigated, and the geologist in his search for new oil deposits must usually be guided by much less definite indications. Interest may attach to an entire region in which rocks of suitable age, known to be productive elsewhere, are present in formations of appropriate thickness and at reasonable depth. The geologist's principal effort will then be directed toward identification and study of any structural features within the region that may seem favorable.

Before entering the field for a regional reconnaissance, the geologist should gather and carefully scan all geologic and topographic information available on the area to be studied. This may be in the form of geologic reports, technical papers or topographic maps. Government and state reports and maps and publications of geologic societies and scientific journals will often provide preliminary information of great value. A carefully prepared topographic map that the geologist can carry into the field is desirable. This should clearly show all topographic relief and important land subdivisions and reference points that can be correlated with the field studies. It should be drawn to such a scale as will permit of geologic field data being accurately detailed. If an appropriate map is not available, the making of one will be the first care of the geologist on going into the field.

Mapping for Geologic Reconnaissance

Topographic maps are made by instrumental methods familiar to all engineers, establishing, first, a triangulation system of reference points to which a plane table survey can be tied or the topographic details may be gathered with transit and level. For rough reconnaissance work, maps of approximate accuracy can be made with the aid of a telescopic hand level equipped with stadia wires, or an Abney level or Brunton compass. Elevations of major reference points are determined with an aneroid

barometer. Only such parts of the area as the geologist indicates as of possible structural interest need be detailed. Photographic methods find occasional use in the preparation of topographic maps; it is possible to construct maps of fair accuracy by taking a series of photographs in various directions from carefully chosen points with a camera of special design.

Use of Aerial Photographic Maps in Petroleum Exploration

One of the greatest conveniences in modern petroleum exploration is found in the use of aerial photographs and maps made in the form of a mosaic of matched photographs taken from the air.[4] In making such photographs, a plane carrying a camera is flown in straight courses over the area to be photographed at an elevation of from 1 to 3 miles. The lens of the camera points vertically downward, and exposures are made at brief time intervals so that the photographs overlap. On completion the resulting photographs are trimmed and fitted together so that they form a continuous strip showing the surface of the earth over which the plane has traveled. If a wide area is to be mapped, the plane is flown in parallel courses over the area, providing sufficient overlap in the exposures so that the photograph strips may be fitted together to form a mosaic of the entire area. To avoid cloud shadows and atmospheric haze, aerial photographs should be made only on clear days, preferably 2 or 3 hr. before or after noon, in order that objects on the surface of the earth will develop some shadow.

Aerial maps have certain definite advantages over ordinary topographic maps. One of the principal advantages is found in the wealth of detail which they afford. The location of every trail, fence line, stream, tree and bush is clearly shown. An area may be mapped much more rapidly by this means than by other methods. As much as 200 square miles may be photographed in a single day, and it has been estimated that 90 per cent of the time ordinarily spent in making topographic surveys can be saved. The cost of maps prepared by this method is consequently lower, ranging from \$65 to \$100 per square mile. An important advantage from the standpoint of the exploration geologist is found in the ability to produce a satisfactory working map of a tract without disclosing to property owners his interest in the area. Such maps also assist the geologist in many ways in the gathering of information upon which he bases his structural interpretations. Before going into the field he may gain an accurate impression of the drainage and physiography of the area. The most convenient means of access to various parts of the locality are apparent, and much walking and climbing during the subsequent field survey are avoided. An important advantage in the field use of aerial photographs or photographic maps is the ability of the geologist to locate quickly his position and orient

(*Courtesy of Continental Air Map Co. and S. C. Herold.*)

FIG. 17.—Aerial mosaic map of the North Dome area of the Kettleman Hills field, California.

himself with surrounding landmarks. Positions numbered on the photographs can be conveniently correlated with geologic observations in the field notebook. Outcrops are often clearly discernible and can sometimes be traced for considerable distances on an aerial map, though their course may not be clearly apparent to an observer on the ground. From the air one gets a comprehensive view of a large area comprising several or many exposures although on the ground he may be able to see but one at a time. Structural conditions beneath the surface may at times be accurately determined from exposures apparent on an aerial map, and there are cases where anticlines overlooked by geologists in the field using ground-survey methods have been later identified by inspection of aerial photographs. Intersections of fault planes with the surface of the earth are often clearly discernible in the photographs. Abrupt changes in color of the surface soil, or in the character or abundance of vegetation, are ordinarily well displayed on an aerial photograph and may be of significance in the search for oil.

In studying aerial photographs an important advantage is gained by observing them through a stereoscope. The stereoscope comprises a system of mirrors and lenses which produces the effect of a third dimension, so that hills, cliffs, trees and other objects on the earth's surface stand out in bold relief. In viewing photographs under the stereoscope, two adjoining and overlapping prints must be properly oriented and spaced apart beneath the mirrors until two images of the same point appear as one. So real is the impression of depth that it is possible to estimate differences in vertical elevation if some horizontal distances on the ground are known. The best stereoscopes for this purpose are intended for office use, but satisfactory folding stereoscopes designed to be carried into the field are also available.

Conduct of Geologic Surveys

Provided with a suitable map, the geologist first enters the field with the purpose of making a broad reconnaissance survey of the entire area to which he is assigned. This will be conducted in such a way as to disclose the more promising areas as early as possible. Early delineation of the more favorable areas is advantageous in order that they may be designated for detailed study which ordinarily follows the reconnaissance survey. If sufficient personnel is available, however, the detailed survey of the more favorable locations may be proceeding simultaneously with further exploration of the areas not yet classified. In reconnaissance work, accuracy is often subordinated to time; it is frequently necessary for the geologist to work rapidly in order that land options and leases can be secured before the attention of competing interests is drawn to the area. When competition for acreage is keen, time may not permit of

a detailed survey of even the more promising areas before an effort is made to acquire the property rights.

With interpretation of geologic structure the primary purpose, attention is directed to the collection of field data that will assist in the determination of dips of flanks and direction and inclination of axial lines of folds. The surface topography is often suggestive of the subsurface structure. Drainage slopes, dip slopes, topographic "highs" and asymmetric ridges are carefully observed by the geologist familiar with physiographic relationships.[2] More exact information relative to subsurface structural conditions is found where the eroded edges of the harder and more resistant strata intersect the surface. Here the dip and strike may be accurately measured, and by taking such measurements at different points along the outcrop of some persistent stratum its disposition beneath the surface may be deduced with considerable accuracy, particularly if a closure on the map is indicated. Where favorable exposures are found, dips are measured with the clinometer, while a Brunton compass may serve to determine the strike. Information so secured is noted directly upon the field map using appropriate symbols. Descriptive notes presenting additional field observations are correlated with the field map by serial numbers. The geologist must always know his exact position on the map in order that observation points may be properly located. Rough triangulation with major reference points, or approximate measurement of distances from property lines and corners, may serve as a means of map location where topographic detail is not adequate. Distances may be determined by pacing, by hand-level stadia observations or by actual tape measurement. The hand level also serves for approximate measurement of relative elevations, and where absolute determination of elevations is necessary the aneroid barometer may be used.

Where the topography is rugged and the formations are steeply dipping, identification of structure is easier than where the area is of low relief and the beds are inclined but a few degrees from the horizontal. In the latter case, resort must be had to careful instrumental methods of survey. It will be important in any case to discriminate between prevailing regional dips and those of local folds superimposed thereon. When the outcrops are obscured by surface alluvium, the position of a stratum must be inferred, though "float" fragments will often fix the position of the stratum between exposures quite definitely. In localities where few well-defined outcrops are to be found, resort may be had to geophysical methods of exploration, described in a later section of this chapter. Faults are an added complexity and their location will often be a matter of considerable importance. Where their line of intersection with the surface can be definitely identified, the direction and amount of displacement will be of special interest. Variation in dips of

formations on opposite sides of an unconformity must receive careful consideration. The direction of ancient shore lines, which customarily display a general parallelism with the trend of bodies of sediment laid down along them, will be significant information.

The geologic field party ordinarily consists of the geologist and one, two or three assistants serving as instrument and rod men. In exploring remote areas, camp facilities and additional assistance may be necessary. Transportation will be by whatever means the locality affords. In regions where conditions are favorable for their use, the automobile and airplane have greatly facilitated the work of the geologist, permitting him to extend the survey far from his base of operations; but in rugged, inaccessible regions, recourse must be had to pack animals.

In gathering the field data, the geologist should be on the alert for any surface indications of the presence of petroleum that may be in evidence, or for fossil indicators that may serve to determine the geologic age of the formations from which they come. Correlation by this means with like formations bearing a definite relationship with oil deposits in other regions will be valuable evidence. Knowledge of the geologic age of the petroliferous horizons of the region, and ability to identify these in the field by paleontological methods, are of great assistance. Paleontology finds one of its chief uses in the field of applied science, in petroleum exploration.

A knowledge of the paleontological and generic relationships* of petroleum greatly aids the prospector in roughly classifying areas which are improbable, possible or favorable for the production of petroleum. Unfavorable areas for the production of petroleum include, generally speaking, the more extensive areas of igneous rocks, all pre-Cambrian strata, intensely folded mountainous areas older than the Cretaceous, regionally metamorphosed strata, continental or fresh-water deposits, thick, uniform marine formations devoid of interbedded dark shales, limestones, marls and fossiliferous sandstones. Possible petroliferous areas include gently folded Cambrian and Ordovician strata, saline-lake deposits, and highly folded marine strata younger than the Jurassic, especially those of Cenozoic age.† The prospector should give special attention to all marine and brackish water sediments younger than the Ordovician, especially if they are not intensely folded or faulted. Conditions are particularly favorable if the formation is made up of porous, thin-bedded sandstones, limestones and dolomites interbedded with shale; and if it appears that the sediments have been deposited in salt water at comparatively shallow depths.

* White, D., Genetic Problems Affecting Search for New Oil Regions, *Trans.* Am. Inst. Mining Met. Eng., vol. 65, pp. 176–198, 1920.

† Woodruff, E. G.: Petroliferous Provinces, *Trans.*, Am. Inst. Mining Eng., vol. 65, pp. 199–216, 1919.

If it seems likely that the results of the field survey will lead to drilling operations, the geologist should select the most promising locations for test wells, with particular reference to structural conditions but also with regard to accessibility, power and water supply and other conditions of practical importance. The results of the geologic field survey are eventually embodied in a report which reviews the work done, comments upon the field observations and presents the geologist's conclusions and recommendations. The latter will deal particularly with the location of proposed drilling operations and acquisition of properties within the prospective area. The report will be accompanied by a copy of the field map, together with structural sections and subsurface contour maps which may have been developed therefrom.

GEOPHYSICAL EXPLORATION INSTRUMENTS AND METHODS

In localities where there are few surface exposures which permit of determining the strike and dip of strata, it is often difficult to form any dependable concept of the subsurface structural conditions. In heavily forested areas, or in valleys where the structural features are obscured by considerable thicknesses of surface alluvium, the geologist following conventional field methods of study may be of little help in locating areas where conditions favorable for accumulation of petroleum exist. In such cases, resort may be had to the use of certain types of geophysical instruments which assist in furnishing information concerning the nature of the subsurface formations. Geophysical data thus assembled may to a geologist skilled in their interpretation provide a means of working out the structural relationships, even though surface signs are lacking or inconclusive. The location of salt domes, faults, buried hills, unconformities and other geologic and structural features may under favorable circumstances often be determined with considerable accuracy by geophysical methods.

Geophysical instruments are designed to measure the magnitude of certain earth forces and lithologic properties that to the trained observer are indicative of the character of rock beneath the surface. They may also provide a basis for estimating the depth below the surface of a stratum having peculiar physical characteristics. Two instruments, the torsion balance and the pendulum, are available for making accurate measurements of the attraction of gravity, which is a function of the density of the subsurface formations. The seismograph in either of several forms may be used in measuring the elastic properties of the subsurface formations of a locality, high explosives being employed to produce earth vibrations, the magnitude and rate of travel of which are recorded by the instrument. Some sedimentary formations contain magnetic minerals so that they locally influence the direction and intensity of the earth's

magnetic field as recorded by a sensitive magnetometer. Earth formations are conductors of electricity in varying degree, and several different instruments are available for measuring earth resistivity or conductivity while others are designed to indicate the magnitude of inductance resulting from flow of electricity through the earth. Radioactivity has been noted in some oil-producing areas, and instruments capable of detecting this property have found limited use. It has also been suggested that instruments designed to measure the ability of an earth stratum to transmit or reflect radio waves may find application, but it has not yet been demonstrated that there is sufficient difference in the extent to which earth formations exhibit this property to provide a practical basis of identification.

The geophysical instruments and methods that have been mentioned in the foregoing paragraph must not be confused with the many different forms of divining rods and "doodle bugs" that have been and still are exploited to some extent by individuals who claim to be able, with the aid of such devices, to locate deposits of petroleum, natural gas and other mineral products of economic value. These devices are supposed to operate either by some supernatural power or influence of the operator, or by some obscure chemical, physical or electrical influence not yet known to science. The informed petroleum technologist will, of course, place no faith in such methods, but an uninformed, credulous public still affords a fertile field for those seeking to exploit their devices and sell their services in the search for oil.

A detailed description of the various geophysical instruments, of the methods used in their operation and in the interpretation of their results, is beyond the scope of the present work. Geophysics is a highly specialized science and is not properly regarded as a part of the field of the petroleum engineer. He should nevertheless be familiar in a broad way with the character of the instruments and methods used and with their possible applications. When geophysical observations and interpretations are to be made, a geophysicist skilled in the use of the instruments and in making the somewhat complex computations must be employed. It is the author's purpose here to present only such an outline of this related field as the petroleum engineer has need of in the work of oil-field development. This general familiarity with geophysical methods is of value to the engineer not only in connection with the problems of petroleum exploration, but it is expected that geophysical instruments may also find application in various phases of oil-field exploitation. Interesting possibilities are found in the use of special types of geophysical instruments in wells, at depths far below the surface, for purposes of correlation of strata from one well to another, location of edge-water lines, determination of the character of fluid content of strata and other related problems.

Gravimetric Methods

It is well known that there are notable differences in the densities of various types of rocks composing the crust of the earth. Where a stratum of rock differs materially in density from overlying and underlying formations, it is possible by making observations at the surface with a sensitive instrument designed to measure the attraction of gravity approximately to estimate variation in depth at various points to its upper surface; or, where a mass of salt or igneous material has been intruded into heavier or lighter sediments, the measured attraction of gravity will locally vary from that normal for the region. As we approach such a locality, there will be a measurable horizontal component of gravity pointing either in the direction of, or away from, the mass of abnormal density, depending upon whether it is heavier, or lighter, than the surrounding rocks. By taking observations which show variation in the attraction of gravity or the gravitational gradient at many different points within an area, it is possible to map the location of salt domes, buried limestone hills and granite ridges; or, where a limestone bed is faulted so that the portion on one side of the fault plane lies nearer the surface than the portion on the opposite side, it is possible to determine the position of the fault plane with considerable accuracy. Two instruments are available for making gravimetric measurements: the torsion balance,[22] a precision instrument of great sensitivity, and the pendulum,[18] less sensitive than the torsion balance but in certain designs sufficiently so for reconnaissance purposes and having the advantage of greater rapidity of operation.

Seismic Methods

Among the more successful of the geophysical methods thus far used in petroleum exploration are those which are based upon the varying speed with which rocks of different types transmit vibrational waves. Their ability to do this is a function of their elasticity. Rocks possess this property in varying degree, the softer, less thoroughly consolidated rocks and formations transmitting vibrational waves less rapidly than the harder, crystalline and well-consolidated formations. It is also found that the older formations generally display a higher speed of transmission of seismic waves than do the younger rocks. Speeds of transmission of seismic waves range from 900 to 7,000 m. per second. In the practical application of this method vibrational waves are developed by detonation of dynamite at a selected point, while sensitive seismographs are placed at some distance away in various directions to receive the vibrations transmitted through the intervening rock formations and record their time of transmission. The time of transmission is very brief: only a matter of a few seconds at most, and an accurate and dependable method

of conveying the exact time of the explosion to the recording instruments must be provided. This is conveniently accomplished by wireless telephony, an electrical circuit being automatically broken by the explosion. Vibrations of the receiving instrument are recorded mechanically and photographically together with a suitable time scale, by reference to which the interval between the time of the explosion and the arrival of the vibratory waves may be determined. Time intervals of 0.01 sec. can be measured.[5]

Several different vibrational waves may reach the recording instruments, and it is important to be able to distinguish between them. One wave moves through the surface formations at comparatively slow speed. This is of little significance. A second wave is transmitted downward into the deeper formations, which often contain some mass or stratum of more elastic material that transmits the vibrational wave more rapidly. Though the path of travel is longer, this deep-seated wave may arrive first at the recording instrument. This latter wave, which is of particular interest to the geophysicist as an indication of the character of the rocks beneath the surface, has two components, termed "longitudinal" and "transverse." The former, which is the component in the direction of movement, is the faster of the two and is the one commonly observed. In addition the recording instrument may receive reflected waves from the upper surfaces of more elastic members of the deep-seated formations. The latter are apt to be locally intensified in certain localities, being dependent upon the angle of reflection from the deep-seated reflecting surface. Sound waves traveling through the atmosphere customarily also reach the recording instruments and may be used as a means of timing the explosion if the distance traveled is known or can be estimated. The speed of the air wave, of course, is much less than that of the earth wave.

In use of the seismic method in the search for salt domes in the Gulf Coast region of Texas and Louisiana, where the method has attained its greatest success, reconnaissance surveys have been conducted over wide areas.

In addition to their highly successful use in the location of salt domes, the seismic methods have been used to advantage in locating fault lines, unconformities and buried granite ridges. They may also find use in identification of structural features whenever a high-speed bed occurs in a mass of less elastic strata and in estimating depths to the basement complex through superimposed sedimentary formations.

Use of the Geophone in Gathering Subsurface Data in Wells.—The geophone is an instrument closely related to the electric seismograph previously described, in that it magnifies and may be used to transmit electrically and record vibratory earth waves. With suitable apparatus the vibrations may be heard as sound, or they may be electrically recorded

by means of the oscillograph.[19] This instrument has the advantage that the receiving instrument can be located at a distance from the recording instrument. The receiving instrument, furthermore, is sufficiently compact to be lowered into a well on an electric cable through which the electric impulses are transmitted to the recording instrument at the surface. With this device it is possible, by successively setting off shots at intervals around the arc of a circle about the well on the surface to estimate the extent to which the well may deviate from the vertical. Correlation of strata from one well to another, near by, is also possible by this means. Other interesting variations of the usual seismic methods are possible when the receiving instrument may be placed at depth within a high-speed stratum the lithologic character of which can be accurately determined by core samples taken during the process of drilling.

Magnetic Methods

As is well known, the earth's magnetic field varies in intensity and direction from point to point and at the same point at different times, but in the vicinity of formations containing concentrations of magnetic minerals important deviations from normal may be locally observed. A compass needle supported in such a way that it may rotate in a horizontal plane tends to align itself with the magnetic lines of force, the angle between the direction of the needle and the true north being its "declination." At any point the magnetic force acting in the direction of the needle in a horizontal plane is called the "horizontal component" of the earth's magnetic field. If a "dipping needle" capable of rotating in a vertical plane about a horizontal axis is placed with its axis perpendicular to the magnetic lines of force, one end of the needle will dip or point downward into the earth. The angle which the needle makes with a horizontal plane is called the angle of dip or "inclination," and the vertical force acting on the needle is called the "vertical component" of the earth's magnetic field.

Magnetometers of several different types are available for exploring the earth's magnetic field, such instruments employing the magnetic needle in one form or another.[17] Some are designed to measure the horizontal component and others the vertical component of the earth's field, but for petroleum exploration purposes one measuring the magnitude of the vertical component is especially useful. The "earth inductor" is another type of instrument that may be used.

Important magnetic anomalies have been noted in the vicinity of many oil fields and in oil-producing regions, but they are apparently not directly connected with the occurrence of oil. They are usually indicative of the proximity of igneous or metamorphic rocks carrying abnormal amounts of magnetite, ilmenite, pyrrhotite and other magnetic minerals.

Distribution of these minerals often has structural significance, but interpretation of such occurrences is usually difficult. Magnetic surveys have been helpful in deciphering structural and lithologic conditions in the vicinity of some of the salt domes of the Gulf Coast region of the United States, in exploring for buried granite ridges and magnetic dykes in Kansas, Oklahoma, north and west Texas and Mexico. Magnetic surveys in some California oil-producing areas are reported to have shown isodynamic contours closely paralleling the structure contours.

Electrical Methods

Electrical methods of geophysical exploration have thus far been less used in petroleum exploration than the gravimetric, seismic and magnetic methods, but possess interesting possibilities for future development. In applying the electrical methods we seek to measure the relative conductivity or specific resistivity of the earth formations of a locality. Ability of different types of rocks to conduct electricity and the resistance offered to transmission of electrical impulses vary widely. In addition to varying conductivity exhibited by the rock mass itself, the character of the fluid stored within its pore spaces has an important influence. Dry rocks are poor conductors in comparison with rocks saturated with saline water. Oil within the pores of a rock, on the other hand, offers very high resistance to the flow of current.[21]

The utility of the electrical methods in petroleum exploration has been questioned by some authorities who find it difficult to correlate structural conditions with electrical observations except under favorable conditions. The absence of any recognizable conducting stratum is sometimes a barrier. Because of the shielding effect of surface formations, it is often difficult to attain any considerable depth penetration. On the other hand, there are cases in which it has been possible by these methods accurately to map buried structures possessing little or no surface expression. An interesting application is found in the use of an electrical method to map structures more than 5-km. off shore, under the bed of the Caspian Sea in the Baku region. One electrical method is said to be effective to depths as great as 6,000 ft. While under favorable conditions it is apparently possible to correlate structural conditions with observations made by electrical methods, the results secured are often difficult of interpretation.

Measurements of Terrestrial Radioactivity

Studies of radiometric emanations from the earth have shown that slight changes in the radioactivity of various earth formations can be detected by comparatively simple photographic, ionization or calorimetric

methods. Radiometric methods were first used in the location of ores containing a high percentage of radioactive substances and for measuring radium emanations in springs producing water used for medicinal purposes. Application of these methods in searching for oil is based on the supposition that since petroleum is an organic compound it has the power of absorbing radioactivity from surrounding formations and that indications of radioactivity at the earth's surface would therefore be more intense in the vicinity of oil deposits. Experiments conducted in the Maikovsky district of Russia by the radiometric subsection of the Institute of Practical Geophysics[20] have shown marked increase in radioactivity in the vicinity of the oil deposits. Other investigators have expressed the opinion that radioactivity observable in certain areas is the result of emanations from radioactive minerals that bear no relation to the presence of oil. In so far as is known to the author, this method of geophysical exploration has not been used in petroleum exploration in other than the region mentioned so that it is not yet known whether it is of general or merely local application. It is of interest, however, as the only one of the geophysical methods which responds directly to the presence of oil.

DRILLING FOR SUBSURFACE INFORMATION IN PETROLEUM EXPLORATION

At times, neither geologic nor geophysical reconnaissance furnishes sufficient information to enable the geologist to form a reasonably accurate conception of the subsurface structural conditions; yet, the locality may be of sufficient promise to justify the belief that if a suitable structure exists, petroleum may be found. In such a case it may be justifiable to expend money in the drilling of one or more wells for subsurface information. In regions where the productive horizons occur in formations unconformable with the overlying beds, the structural relationships below the unconformity may be impossible to decipher without the information that may be furnished by one or more wells drilled from the surface to intersect the lower formations. A single well may furnish cores of the formation penetrated, which provide an accurate record of the lithologic characteristics of the component strata, and if the well is vertical and the cores can be properly oriented the approximate dip of the formations can be determined. The logs of two wells permit of some degree of correlation from which approximate calculations of the inclination of strata between the two locations may be made. Three or more wells provide information for a complete and accurate determination of the dip and strike of any continuous stratum that can be definitely identified in each.

Drilling for structural information is often conducted with the aid of the diamond drill (see page 249), which affords excellent cores and, when

light portable outfits are used, is more rapid and less expensive than drilling by churn or rotary methods. However, portable and semi-portable rigs of both churn and rotary type are also occasionally used for this purpose. Wells drilled for structural information are often but a few hundred feet deep, though there are many instances in which deep wells have been drilled, primarily with the purpose of securing sub-surface geological data. Such wells are often smaller in diameter than those drilled for production purposes, frequently only 2 to 5 in. In the event that a productive oil sand is encountered, and it is desired to produce through them, they may be reamed to a larger diameter at small cost. However, if the well is to be of considerable depth and it is thought that there is a fair chance of securing commercial production, it will generally be preferable to drill a full-sized hole by the usual cable-tool or rotary methods. In the event that production is secured, it is difficult to make a fair test of the productive capacity of an oil-bearing stratum in a well of less than normal diameter.

LOCATING TEST WELLS

Having deciphered the subsurface structural relationships, and having reached a decision that conditions seem sufficiently favorable to justify the drilling of a test well, it will next be the task of the exploration geologist to select the most promising position for the well. In locating test wells the geologist will be primarily influenced by structural conditions, but, in so far as it is consistent with this, he will also be influenced in making his selections by considerations of accessibility and property ownership. It will, of course, be essential that title be secured to the property upon which the test well is to be drilled or, at least, the right to drill and produce and remove oil and gas therefrom. It will also be desirable that the exploration interests secure title to a sufficient surrounding acreage to guarantee a reasonable profit on their activities in the event that the test well proves to be commercially productive. Methods of acquiring title to oil land are described in Chap. III.

Structure being the primary consideration, the geologist will strive so to locate the test well as to secure the maximum advantages that structure affords.

Locating Test Wells

In locating test wells on dome and anticlinal structure, the prospector should aim to penetrate the petroliferous stratum at its structural crest. Here nature's forces are concentrated—the gas pressure is greatest, and the possibilities of high and long-continued production are at their best. A well drilled in any other location, if unproductive, would still leave the presence or absence of oil in the formation in doubt. An unproductive

well on the structural crest settles the issue at once unless there is reason for believing that the sands are lenticular or are influenced by irregular cementation. The only exception to this general rule of locating the test well to intersect the supposed oil-bearing stratum at its structural crest is found where abnormally large gas concentrations under high pressure are expected, owing to unusually favorable structural conditions. In such cases, a well directly on the crest of the structure might produce only high-pressure gas for a considerable period before oil could force its way up from lower levels into the well. A well located slightly down-dip from the structural crest would in such a case produce oil at once and could be operated under more favorable conditions.

It is well to remember in selecting sites for test wells on asymmetric anticlines that the productive limits of the pool will probably extend farther from the axis in the direction of the flat-dipping flank than on the side of the steeply inclined flank (see Fig. 2). Consequently, if there is doubt concerning the precise location of the axis, preference should be given to the flat-dipping side in locating the initial well.

In determining the location of axes of asymmetric folds at depth from surface measurements, it should be noted that the axis of a stratum several thousand feet deep may be in quite a different position from the axes of the surface strata, though they are parts of the same fold. This is demonstrated in Fig. 2, in which it may be observed that the axes of the deeper strata fall successively to the right of the overlying strata. It is obvious that a careful structural study based on accurate field data is essential before a test well can be properly located to penetrate the oil stratum at its structural crest.

In locating test wells on monoclinal structure, the wells must be located sufficiently down-dip to penetrate the oil stratum below the zone of surface influence, which may extend for several hundred feet below the outcrop. Oils produced from the upper portion of the stratum, near the outcrop, are likely to be heavy and viscous, and the wells will be small producers because of the difficulty of inducing flow from the sands and because of the absence of gas. Except for this limitation, considerations influencing location of wells on monoclinal structure are identical with those discussed in connection with anticlines and domes. If the dip of the outcropping strata is measurable, it is a simple matter to calculate from the observed angle the proper distance of the well from the outcrop, to intersect the oil zone at any desired depth.

The location of test wells with respect to other types of structures than those discussed in the foregoing paragraphs presents a somewhat more complex problem, and one upon which it is difficult to generalize. Where faults enter as a factor in determining the structural relationships, one should remember that the possible oil accumulations are always on the side of the fault plane in the direction of the downward-dipping

formations. If however, this happens to be on the "foot wall" or underside of the fault plane, it may be necessary to drill through the fault plane and hence to locate the wells at the surface on the side opposite to that on which the accumulation is conceived to occur (see Fig. 12). Abrupt changes in the strike of the fault plane may be particularly significant. A still more uncertain situation is presented in locating test wells on salt domes. Oil may not be present at all, or, if it is, it may be in the sediments on one side of the dome but not on the others, or there may be an accumulation on top. Several or perhaps many test wells may be necessary before a salt dome can be abandoned as non-productive. Where an unconformity intervenes between the surface exposures and the formations in which production is sought, or where there is reason to believe that the oil reservoir rock is highly lenticular, most uncertain conditions are presented and much more or less "blind" drilling may be necessary to test adequately the productive possibilities of an area.

SUBSURFACE INDICATIONS OF PETROLEUM THAT MAY BE OBSERVED IN THE DRILLING OF A WELL

During the drilling of a test well there are occurrences that may be significant in indicating the proximity or presence of petroleum. Knowledge and observation of these will enable the geologist to advise those in charge of drilling operations concerning the prospects for further drilling. Even when the surface signs are unmistakable, the evidence to be obtained from the log of the well during the drilling stage will be of great value in checking previous estimates and also in the subsequent development of the field through the drilling of additional wells.

Oil-saturated sand or even traces of oil in the pulverized material bailed or pumped from the well are, of course, direct evidence and usually justify a pumping test of the stratum from which they come. Such a test is often necessary to determine whether or not oil can be produced in sufficient quantity to repay the cost of operation. The driller will always be on the alert for "shows" of oil when the drill enters a soft, porous sandstone after penetrating a hard layer of close-grained "shell." It will often happen that the finely pulverized material pumped or bailed from the well will be so thoroughly washed that its petroliferous character is not evident until tests are made. An ether, chloroform or acetone test will usually disclose the presence of oil.

Flows of hydrocarbon gases from a drilling well are always favorable evidence, especially if they contain gasoline vapors or if they have a petroleum odor. Many sedimentary formations produce marsh gas (methane) which, if dry (that is, without hydrocarbons of higher molecular weight) is often formed in the absence of petroleum, and therefore it is not necessarily indicative of the presence of oil.

Traces of solid or semisolid hydrocarbons, such as mineral wax, asphalt, fossil resin, tar or even coal or lignite, in the returns from a well constitute favorable indications of the presence of oil.

Waters and gases containing hydrogen sulphide or sulphur dioxide are generally favorable indications unless the water is hot. Hot sulphur waters are characteristic of regions under the influence of volcanic and solfataric activity, conditions generally unfavorable for the accumulation of petroleum.

The presence of igneous or highly metamorphosed rocks is necessarily regarded as unfavorable for the discovery of petroleum in the formations beneath. Brine is generally looked upon as an unfavorable indication when encountered in a prospect well. Though it is nearly always associated with petroleum, it generally underlies the oil; consequently, if a well produces brine, it is often inferred that the zone in which oil might be found has been penetrated and found barren.

Aside from the more direct indications of petroleum suggested above, it should be pointed out that mere alternations of stratified porous and impervious beds in horizons known to be petroliferous are in themselves favorable indications. Great thicknesses of either coarse or close-grained rocks, without variety in porosity and texture, never offer favorable conditions for the accumulation of petroleum.

Dissolved Salts Present in Ground Waters Sometimes Significant

In some fields it is found that the percentage of certain dissolved salts in the ground waters increases or decreases in a characteristic manner. In such cases it is possible to form some estimate of the proximity of an oil sand from a chemical analysis of the waters contained within the various strata penetrated by the well. Waters a short distance above the oil horizon in many fields are "sulphur waters," containing considerable percentages of hydrogen sulphide; but the shallow surface waters and those within the oil measures generally contain no sulphides. Carbonates, which are present only in moderate amounts in the shallow waters, increase in percentage as the oil zone is approached. If no chlorides are present, the carbonates may constitute the only dissolved salts in the waters immediately associated with the oil. As pointed out in the preceding paragraph, however, the waters underlying petroleum, occupying the lower horizons of the same strata in which the oil occurs (that is, "edge waters"), are often rich in chlorides. Although the surface and shallow ground waters contain considerable percentages of dissolved sulphates, these are found to diminish as the oil measures are approached and finally entirely disappear. Outside of localities in which petroleum occurs, on the other hand, sulphates are found in even the deepest waters.

Geothermal Gradients

Measurements in wells of the rate of temperature increase with depth have shown that in many oil fields the rate of increase is greater than is normal in sedimentary formations in the same region.[15] Various theories have been offered to account for this. Some authorities have suggested that it is possibly due to some obscure chemical reaction in which petroleum plays a part, but information recently obtained in several different petroleum-producing regions indicates that petroleum itself probably is in no way responsible. In a number of oil fields where detailed studies have been made of the geothermal gradient, it has been found that variation in the gradient bears a direct relation to structure, showing the most rapid rate of increase at the structural crest. Some observers believe that circulating ground waters are responsible for variations in the gradient that have been observed. In other instances it appears that proximity to igneous or metamorphic rocks may be the explanation of an unusually rapid rate of increase in ground temperature with depth.[11] It has also been suggested that local radium emanations may be active in influencing ground temperatures, but there is little or no evidence to substantiate this view. The present data are too uncertain in character to justify any definite correlation between ground temperatures and proximity to oil-bearing strata, but the information so far collected would appear to substantiate the general statement that ground temperatures higher than normal prevail in petroliferous formations. In this connection, however, the fact should not be lost sight of that high ground temperatures are also characteristic of regions where vulcanism is active and that, without more direct evidence of the presence of petroleum, ground temperatures are of doubtful significance.

Geologic Reconnaissance Not an Infallible Guide

Equipped with a knowledge of the characteristics of petroleum, with its manner of formation and accumulation, its associations and occurrence in nature, it is the task of the prospector to apply this knowledge in the field in the location of new deposits. The nature of the work requires a happy combination of technical and practical ability, a power to reason and deduce facts which must often be based on very slender and uncertain evidence. Geology is not an exact science. Good judgment and practical experience in field methods are of far greater value than mere academic understanding. Usually it will not be possible for the geologist to predict with certainty that petroleum will be found in commercial quantities in a given location. Perhaps the best information to be expected from him will be a statement that conditions are either favorable or unfavorable; and if favorable, the best position within the prospective area for the location of a test well should be selected by him. The

possibility that a well thus located by scientific methods may prove unproductive is one of the inherent risks in petroleum exploration that must be recognized by all parties concerned in the enterprise.

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CHAPTER III

ACQUISITION OF TITLE TO OIL LANDS

Before any drilling is begun the prospector must acquire title to the land to be tested; or, at any rate, he should conclude an agreement with the land owner that will protect him in his right to prosecute drilling operations and to produce and sell any oil or gas that may be discovered. In the United States, if the area containing the proposed site of the well is a part of the public domain, the privilege of prospecting may be secured by making application to the U. S. General Land Office. If land in the vicinity of the well is privately owned and is low in price, the prospector may find it to his advantage to purchase a moderate acreage outright, perhaps acquiring a preferential right to surrounding land by securing options. It is to the advantage of the prospector to secure title to the necessary land before his purpose is generally known in the community, for the mere knowledge that someone thinks highly enough of the prospective merits of the locality to sink a well is often sufficient to inflate values. If the presence of petroleum is unknown or unsuspected in the locality, the privilege of drilling and producing any oil that may be found can usually be acquired at small cost on a leasing basis without actually purchasing the land; in many cases the landowner will permit a test well to be drilled, merely on the stipulation that he shall receive a certain percentage of any oil or gas that may be produced, and without the payment of any initial sum by the prospector. Such a plan is very favorable to the landowner, for he loses little or nothing if the test fails and yet is assured of a substantial part of the profits if it is successful. If the presence of oil in the locality is known or suspected by the landowner, a leasing agreement is sometimes the only feasible plan, owing to the owner's desire to share in any oil that may be discovered.

ACQUIRING CONTROL OF PROSPECTIVE OIL LAND UNDER U. S. MINERAL LAND LAWS

Land containing oil and gas is classified as mineral land under the U. S. Land Laws, and the right of entry and exploitation is open to American citizens under the U. S. Mineral Land Laws.[4] Prior to March, 1920, locations could be made and title secured under the Placer Law of 1872, but the Mineral Land Leasing Law of 1920, which is now operative, established the principle that title to oil and gas, coal and certain other minerals on government-owned land should reside in the national govern-

ment, and that the privilege of producing oil might be secured only for a definite period of time under a lease-and-royalty system.

The Placer Law of 1872

The Placer Law of 1872, under which many present oil-producing properties were acquired, if on the public domain, provided that any citizen or alien who had declared his intention of becoming a citizen of the United States could preempt a tract of 20 acres or less in conformity with the general land subdivisions, and associations of eight or more individuals could make a joint location of 160 acres.[5] The exclusive privilege of searching for and producing oil from the area so claimed was secured by merely staking it, posting a notice on the ground and filing a claim for it at the nearest public land office. Thereafter the claimant retained his exclusive rights as long as he expended at least $100 in developing the property during each calendar year. If he failed to perform the annual "assessment work," the land became subject to relocation by any other claimant. After $500 had been expended in developing the "claim," the law provided that the locator could secure a patent conveying absolute title, without the obligation of performing further assessment work, on payment of a certain nominal sum per acre and having the land surveyed by a licensed mineral land surveyor. Certain provisions of the Placer Law were found to be inappropriate when applied to oil and gas land, and in 1909 large areas of prospective oil land on the public domain were withdrawn from entry pending the passage of a leasing law, which, however, was not passed by Congress until 1920. Placer claims located under the law of 1872 are still valid as long as the provisions of the old law are adhered to.

The Mineral Land Leasing Law of 1920

The Mineral Land Leasing Law of 1920 applies to petroleum, natural gas, oil shale, coal, phosphate and saline deposits still remaining on the public domain.[4] Under its provisions, lands containing these mineral products are permanently withdrawn from location and patent under the earlier mineral land laws and can be exploited only on a leasing basis involving payment to the government of a bonus, an annual rental and a royalty or percentage of the mineral produced. The exclusive right to prospect for these minerals on the public domain is granted for particular areas having specified boundaries through the issuance of a prospecting permit by the Secretary of the Interior or his representative.

Prospecting permits may be granted to any citizen of the United States or to any corporation, a majority of the capital stock of which is held by citizens of the United States. The permit grants to the applicant the exclusive privilege of prospecting for oil and gas within an area of 2,560 acres (4 square miles) or less, for a period of 2 years. However, a

prospecting permit cannot be issued to grant such privileges within the geologic structure of any producing oil field. The area covered by the prospecting permit must be rectangular, reasonably compact in form and not more than $2\frac{1}{2}$ times as long as it is wide, and it must conform with the public land subdivisions if the land has been surveyed. Non-contiguous tracts within a limited radius may be included in a permit when conditions are such that, because of previous grants under other laws, a reasonable area of contiguous land cannot be procured. The area comprised within a permit may not include land within any national park, forest reserve, Indian reservation or in military or naval reservations. The applicant may not hold more than one permit on the same geologic structure or more than three subsisting permits within the same state. He must furnish three references certifying to his good reputation and business standing, as well as a bond of $1,000 conditioned against his failure to repair promptly any damage that may be done through improper methods of drilling and operation.

The holder of a prospecting permit must mark all corners of the area covered by the permit and must commence actual drilling operations with a "substantial and adequate drilling outfit" within 6 months. Within 1 year he must drill one or more wells to a depth of at least 500 ft., and within 2 years he must drill at least one well to a depth of 2,000 ft. or more, unless valuable deposits of oil or gas are found at shallower depths. Other individuals holding surface rights in the area covered by a permit must be reimbursed by the prospector for any damage to crops, buildings or other property. Twenty per cent of the gross value of all oil or gas produced must be paid to the government until such time as a lease to the land is granted.

The life of a prospecting permit may be extended over a second 2-year period if in the opinion of the Secretary of the Interior additional time is necessary to test the land. Some modifications are introduced into the time limits specified in the issuance of prospecting permits for lands in Alaska, because of the difficulty of conducting drilling operations in that region. If oil or gas is not discovered on the area covered by the permit within the specified time, the permit terminates and the land automatically reverts to the government. The government reserves the privilege of granting prospecting permits or leases for other minerals than oil or gas on the same area, together with right of entry for other parties holding such permits or leases.

Reward for Discovery.—Upon establishing to the satisfaction of the Secretary of the Interior that valuable oil or gas deposits have been discovered within the limits of the land embraced in a prospecting permit, the owner of the permit is entitled to a lease of one-quarter of the land included within the permit, or for at least 160 acres if there be that area included, on a royalty of 5 per cent of the gross value of the oil and gas

produced. The discoverer of oil and gas is entitled to a preferential right to lease the remainder of the land included within his permit at such royalty as may be fixed by the Secretary of the Interior and under such conditions as may be required of other lessees in the same locality.

Leasing of Government-owned Oil and Gas Lands on Geologic Structures Known to Be Productive.—All public lands known to be productive of oil and gas before the passage of the leasing law of 1920, and all areas not covered by prospecting permits which have been proved productive since 1920, may be leased from time to time by the government, at a stated royalty, not less than 12½ per cent,* to be determined in each case, or an annual rental of $1 per acre for so long a time as the land may remain unproductive. The land is divided into tracts of 640 acres or less—areas not more than 2½ times as long as they are wide—and the tracts are offered for lease at auction to competitive bidders. The lease is awarded to the individual or company offering the largest bonus, the bonus so offered representing the amount that the bidder is willing to pay for the lease in addition to the set royalty or annual rental.

The successful bidder must furnish a certified check for one-fifth of the amount of his bid on the date of sale; and he must also file a statement certifying that he is a citizen of the United States, or in the case of a company the articles of incorporation must be filed together with a statement indicating the residence and citizenship of its stockholders. The bidder may not hold another lease on the same geologic structure, or more than two other leases, or a lease and a prospecting permit, within the same state. On being awarded the lease, the successful bidder must pay the remaining four-fifths of his bonus within 30 days, together with the first year's rental of $1 per acre. He must also file a bond of $5,000 to be forfeited to the government in case of failure to comply with any of the terms of the lease.

The lease conveys exclusive rights to drill for, remove and dispose of oil and gas from the land for a period of 20 years, with a preferential right to renewal for successive 10-year periods at such terms as may be agreed upon by both parties. The government recognizes no obligation to renew the lease unless the lessee is willing to meet the terms offered by competitive bidders. The lessee must proceed to drill the land within 3 months from the date on which the lease is granted, continuing development until there is at least one well on each 40-acre tract. The annual rental is credited against the royalty payments—that is, rental is actually paid on a producing lease only when the royalty payments amount to less than $1 per acre per year. It is provided that the government may

* In practical administration of the law, a sliding scale of royalties varying from 12½ to 33⅓ per cent, depending upon the productivity of the wells, has been prescribed.

reduce the royalty payments when the production of a well falls below 10 bbl. per day, if it appears in the interest of the government to do so.

The lessees must provide the government with copies of all sales contracts, monthly statements of production, well logs and other essential data in evidence of proper payment of royalties, and as proof that the work is being properly conducted. Government agents have access to the property and the records at all times. Many other details covering such matters as payment of taxes, wages, prevention of waste, assignment of leases, easements or rights of way, action in case of abandonment of property or default in terms, etc., are discussed in the *Regulations* of the General Land Office.[4] Administration of the law, once the leases have been granted, has been placed under the control of a division of the U. S. Geological Survey.

The government has the right, whenever it may be deemed in the public interest, to withdraw mineral lands on the public domain from entry under the leasing law. During such times as areas are withheld, no prospecting permits or leases may be issued. President Hoover exercised this privilege in 1928 in withdrawing all unappropriated oil and gas lands on the public domain from entry. This was at a time when an acute condition of overproduction of petroleum existed.

State-owned Oil and Gas Lands

Under various congressional grants and by constitutional provision, certain public lands have at times been allotted to the several states under conditions that permit of future conveyance by such terms as the individual states may prescribe. In some states, for example, land has been allotted with the intention that the money derived from the sale thereof shall be devoted to educational activities. Some of this land has later been found to contain oil or gas and has been the source of considerable income to the states concerned. In some cases, river, lake beds and tidelands belonging to the states have been developed for oil production. The conditions under which such land may be purchased or leased by individuals vary in the different states according to legislative enactment. Though some state lands have been sold outright, they are customarily leased under a royalty system, often with competitve bonus and rental features similar to those of the national leasing law. Such laws have been enacted by California, Oklahoma, Texas, Louisiana, Ohio, Wyoming, Montana, Nebraska, South Dakota, Colorado and Utah.

Oil and Gas Rights on Indian Reservations

Certain lands set aside as Indian Reservations in Oklahoma include extensive oil deposits of great value. Though such lands were originally inalienable or non-transferable, various subdivisions from allotments of the tribal estates to individual members have been authorized from time

to time and some of the earlier restrictions against sale of the land have been removed, particularly in the case of Indians of partly white heritage. Leases may also be obtained from full-blooded Indian owners with the approval of the Secretary of the Interior and the Office of Indian Affairs.[1] Congress has passed special legislation covering lands owned by the Osage Indians, allotting surface rights to individual members of the tribe but reserving mineral rights to the tribe as a whole. Leases may be authorized by the tribal council and are sold from time to time at auction to competitive bidders through the Department of the Interior. A royalty of 20 per cent is exacted for wells producing 100 bbl. of oil per day or more, and 16⅔ per cent for wells of less than 100 bbl. The lease agreements provide that a well must be drilled on the property to the Mississippi Lime, a formation underlying the oil horizon, unless commercial production is obtained at shallower depths.

The Legal Aspects of Oil and Gas Land Ownership in the United States

Though classed as minerals, and therefore subject to the provisions of the United States Mineral Land Laws, it is recognized by the courts that petroleum and natural gas have peculiar attributes which distinguish them from solid minerals.[2] Both petroleum and gas, as long as they remain in the ground, are a part of the realty; that is, they belong to the owner of the land and are a part of it, as long as they are subject to his control. When they migrate to neighboring properties and come under another's control, the title of the former owner is gone. The owner of the land has no specific title to the oil and gas within his land unless he takes actual physical possession of them; that is, until they are brought to the surface and reduced to actual possession. Thereafter, they become the personal property of the owner of the well through which they are produced.

The ownership of the surface of the land may be separated from that of the different strata beneath it, and there may be as many different owners as there are strata. Hence, surface rights may be separated from mineral rights in the sale of land; but unless specifically reserved, oil and gas rights pass with the transfer of title to the land surface. A person who has title to subsurface minerals, but who lacks surface ownership, has the right to build a road over the land when necessary to haul machinery to the place selected for a well, and to such other use of the surface as may be strictly necessary for drilling and producing purposes. The right to drill wells to produce oil and gas from lower strata through a deposit belonging to another, as in drilling an oil well through a coal seam, exists at all times, although it must be exercised in such a way as to do no damage to the property of others.

Many complex questions arise in considering the rights of neighboring landowners producing oil and gas from the same reservoir. The courts have generally recognized the principle stated above, that the oil and gas does not belong to the landowner until reduced to actual possession at the surface; but the right to drill wells and produce oil or gas from one's own land is absolute and cannot be enjoined, supervised or controlled by a court or by an adjoining landowner unless unnecessary negligence resulting in damage to the common source can be shown. Under this interpretation, a landowner who drills a well into an oil deposit and allows the gas to escape and to waste cannot be restrained by injunction unless unnecessary negligence is evident. However, in some states statutes have been passed designed to prevent waste of gas or damage by infiltrating water, and these statutes have been declared valid. The principle upon which such legislation has been upheld is that no one has a right to waste natural resources to the injury of the public or to wantonly destroy or injure a common reservoir in which others have an equal right. Although the owner of a well, according to one authority, may explode nitroglycerin or apply vacuum pumps or other artificial devices to increase the productivity of his wells at another's expense, there are also decisions to the effect that a court of equity may, under common law principles, enjoin a landowner from using such devices.

OIL AND GAS RIGHTS IN FOREIGN COUNTRIES

Abroad, oil and gas rights are almost universally regarded as property of the state, and ownership of minerals is usually separate and distinct from ownership of the surface.[5] Particularly is this true of the Latin-American countries which trace their conceptions of law back to the early Roman law, in which ownership of all beneath the surface of the earth belonged to the empire, agricultural settlers on the land being given only surface rights. Throughout Latin-America, the principle that no one may obtain fee simple title to mineral land is fundamental. Possessory right, subject to continued payment of an annual tax, is the only form of title given.

Mexico

In Mexico where the Latin system has attained its highest development, prospecting for minerals is free to all citizens, both on the public domain and on property owned by private individuals.[3] Upon discovery of mineral, a notice must be posted on the premises and a copy filed with a local government official. The claimant is then given the exclusive privilege of conducting exploration work for 3 months, and if he so desires he may then locate his claim or claims. After the claim is staked, the location notice must be published in the nearest local newspaper and the ground surveyed by a government engineer. After a period during which

adverse claims may be brought forward, the claimant is given absolute title which is maintained as long as he continues to pay taxes, rentals and royalty. The unit mining claim, called a "denouncement," is 1 hectare, or a horizontal square area measuring 100 m. on each side and containing 2.471 acres. Four hectares constitute a petroleum denouncement, and any number of such units may be located by one individual either in groups or separately. If the surface of the property is owned by another, it is necessary to secure his consent before development work is begun, usually by a money payment; but it is provided that if an equitable adjustment cannot be effected by direct negotiations with the owner, the land may be condemned by court proceedings. In addition to taxes, an annual rental of 5 pesos per hectare must be paid to the government, and a 5 per cent royalty on gross production of oil and gas. Three years are allowed in which to begin development after the claim is staked.

Prior to 1917, the earlier mining laws of Mexico did not nationalize petroleum and natural gas, the owner of the surface being conceded ownership to all hydrocarbons; but this was altered during the Carranza régime and present laws consider all minerals, as well as hydrocarbons, the property of the government. The present laws are not intended to be retroactive, that is, leasing agreements made with landowners under the old laws are still valid. However, considerable confusion has arisen through the efforts of the Mexican government to collect royalty taxes on land held under lease from private owners and in some cases conflicting claims have been allowed for the same land. The situation has been further complicated by the establishment of 20-m. "federal zones" along the sea coasts and zones 10 m. in width along the shores of inland lakes, lagoons and water courses, in which concessions for development and production of petroleum were for a time granted on a rental and leasing basis in direct conflict with previously established property rights in the same areas.

Canadian Laws

Canadian laws governing oil and gas rights vary somewhat in the different provinces of the Dominion.[3] The Dominion government has jurisdiction only over unappropriated Crown lands in Manitoba, Saskatchewan, Alberta, the Northwest Territories, the Yukon Territory and within certain areas in British Columbia. Separate laws have been established governing the disposition of lands belonging to the provincial governments of British Columbia, New Brunswick, Ontario and Quebec.

The Dominion laws of 1904 provide that prospecting shall be free, a prospecting permit giving exclusive privileges on an area of 1,920 acres for a limited time; and if oil is produced in paying quantities, the prospector may secure a patent to 640 acres on payment of $1 per acre and the remaining 1,280 acres at $3 per acre. The law of 1914 makes provision

for leasing Crown lands for 21-year periods on payment of an annual rental of 50 cts. per acre during the first year, and $1 thereafter. It is provided, however, that rentals for the second and third years may be reduced by the amount expended by the prospector in conducting drilling operations, exclusive of casing and machinery.

The maximum area for a petroleum and natural gas location is 1,920 acres, and no person is permitted to acquire a greater area except by assignment. The lessee must commence drilling within 15 months of the date of his lease, and continue development with "reasonable diligence," the expenditure of $2,000 or more per year on each lease being considered as fulfilling the obligations of the lessee under this provision. Exploitation of Dominion oil and gas lands is open only to citizens of Canada, or to registered or licensed companies having their principal places of business in Canada. Further legislation in 1920 extended the above provisions to include all Dominion forest reserves.

Revised regulations governing prospecting for oil and leasing of lands in the Northwest Territories were announced following the discovery of oil at Fort Norman in 1920. Prospecting permits cover a maximum area of 2,560 acres and extend over 4 years' time. Annual rentals are as stated above, and the prospector is obligated to begin drilling within 2 years and to drill a 2,000-ft. well before the end of the fourth year unless commercial production is secured at a shallower depth. On discovery of oil, the operator is entitled to a 21-year lease on one-quarter of the area of his prospecting permit, for which he must pay an annual rental of $1 per acre and a royalty of 10 per cent.

Regulations governing prospecting and leasing on provincial lands are very similar to those outlined above, except that the payments exacted for prospecting permits, rentals and royalties differ somewhat in each case. Such royalties as are assessed are generally low, most of the burden on the operator being in the form of annual rentals.

ACQUISITION OF OIL AND GAS LAND FROM PRIVATE OWNERS

Oil and gas land may be acquired from private owners either by purchase in fee or by leasing. The latter is the more common method because it is less costly, though the former gives greater security and freedom from restrictions.

Purchase in Fee

Actual purchase of the land is seldom economical if one is interested only in securing oil and gas rights, and a method involving purchase of mineral rights or oil and gas rights exclusively will usually give the purchaser ownership of that which he seeks, without obligating him to pay for surface rights in which he is not interested. The risk involved in purchasing land or mineral rights may be somewhat reduced by arranging

that payment shall be made in installments over such a period of time as will permit a test to be made of the land before full payment is made.

Leasing

A lease may take a variety of different forms, ranging from a simple agreement conveying the right to produce and sell oil from the property for a stated period of time and for a stated consideration, to more complicated contracts called "working bonds," which grant a lease involving term payments, or rentals, with option of purchase, or lease, before a specified date for an agreed sum. The ordinary form of oil and gas lease provides for transfer of title to all oil and gas obtainable from the land during a stated period of years, or during a period limited by certain contingencies. The consideration is usually a percentage of the gross value of the oil and gas produced—often one-eighth—though, in many cases, it will also be provided that the lessee shall pay in addition an initial payment called a "bonus" and perhaps also an annual rental. The instrument by which such rights are conveyed must be drawn up in legal form, care being taken to state all of the conditions under which the lease is granted and the rights of the two parties to the agreement. On pages 67 and 68 will be found a typical form* for an oil and gas lease.

Terms of the Lease. *Royalties, Rentals and Bonuses; Drilling Requirements.*—The terms which a landowner may exact for a lease depend upon the prospects for securing production. If his land is remote from productive acreage and the presence of oil beneath the tract is uncertain, he may have to be content with a small royalty on the future production, that is, the lease may be granted without any immediate cash consideration or bonus. On the other hand, if the land in question is near productive territory and the structural conditions seem favorable, the landowner will be in a position to demand an initial payment in addition to a substantial royalty. Both parties to the agreement naturally want to secure the most favorable terms. The landowner, being, as a rule, more or less unfamiliar with the business of oil development and susceptible to the popular conception that huge profits are the rule, is apt to be unappreciative of the risks involved and the great cost. He accordingly is inclined to demand more than the lease is worth. The bonus demanded may be anything up to $1,000 or more per acre, and royalties range from 5 per cent of the gross value of the oil up to 50 per cent. A balance agreeable to the landowner must be determined between the bonus offered and the royalty, for the two are interrelated. Some owners prefer to have a large initial payment and a smaller percentage of the profits in the event of success, while others will be willing to share the risks and receive a smaller bonus and a larger royalty. In general, the lessee prefers to

* Printed copies of this form may be secured from the Petroleum World & Oil Age Publishing Co., Los Angeles, Calif.

Lease

THIS INDENTURE OF LEASE, made and entered into this____________________

day of____________________19____, by and between____________________

____

____

hereinafter called the Lessor (whether one or more), and____________________

____

hereinafter called the Lessee,

Witnesseth

That the Lessor, for and in consideration of Ten Dollars to him in hand paid, the receipt whereof is hereby acknowledged, leases to the Lessee, all those certain pieces or parcels of land situate in the

County of____________________, State of California, and more particularly described as follows, to-wit:

Said lease shall be on the following terms and conditions:

1. Said lease shall continue for a period of twenty years from and after the date of this agreement, and so long thereafter as oil or gas may be produced on the demised premises in paying quantities.

2. The Lessee shall have the sole and exclusive right of prospecting demised premises and drilling for and removing oil and gas therefrom, and to establish and maintain on said premises such tanks, boilers, houses, engines and other apparatus and equipment, power lines, pipe lines, roads and other appurtenances which may be necessary or convenient in the operation or production of oil or gas from said property. The Lessee shall have the right during the term of the lease to drill for and develop such water on said premises as it may require in its operations.

3. The Lessee agrees to start the drilling of a well for oil within________________from the date of this agreement, and to continue the work of drilling such well after commencing the same with due diligence until a depth of__________feet has been reached, unless oil is discovered in quantities deemed paying quantities by the Lessee at a lesser depth, or unless such formations are encountered at a lesser depth as will indicate to the geologist of the Lessee that further drilling would be unsuccessful.

4. After discovery of oil in said paying quantities in the first well, the Lessee agrees to commence the drilling of a second well within ninety (90) days thereafter, and thereafter continuously operate one string of tools, allowing ninety (90) days between the completion of one well and the commencement of the next succeeding until__________wells have been drilled, including offset wells. Nothing herein shall be considered to limit the number of wells which the Lessee may drill, should it so elect, in excess of the number hereinabove specified.

5. The Lessee may at any time before discovery of oil on the demised premises quitclaim the said property or any part thereof to the Lessor, his successors or assigns, and thereupon all rights and obligations of the parties hereto one to the other shall thereupon cease and determine as to the premises quitclaimed.

6. After discovery of oil, the Lessee may at any time quitclaim any part of said land to the Lessor, his successors or assigns. Upon the quitclaiming of any part of the land to the Lessor, his successors or assigns, drilling requirements shall be reduced pro rata according to acreage. On the expiration of the twenty year period, no further wells shall be drilled upon said property and all rights of the Lessee therein shall cease, except that the Lessee shall have the right to operate, deepen, redrill and properly maintain all producing wells upon the property at that time, and to use so much of the surface of the land as may be necessary or convenient for such operations. Except as herein provided, full right to said land shall revest in the Lessor free and clear of all claims of the Lessee, except that the Lessor, his successors or assigns, shall not drill any well on said land within an area of ten acres surrounding each producing well.

7. In the event of the discovery of oil in any well on adjacent properties within one hundred and fifty feet of the boundary lines of the demised premises, and the production of oil therefrom in paying quantities for a period of thirty days, then the next well to be drilled hereunder shall be so placed to offset said well on the adjacent property, or if no well is being drilled and the total well requirements of this lease have not been fulfilled, then within ninety days thereafter a well shall be commenced by the Lessee to offset such producing well on the adjacent property.

8. Drilling and pumping operations shall be suspended on said property only in the event that they are prevented by the elements, accidents, strikes, lockouts, riots, delays in transportation or interference by state or federal action, or other causes beyond the reasonable control of the Lessee, or so long as the price of oil of the quality produced on said property shall be less than seventy-five cents a barrel at the well.

9. The Lessee may extend the period of commencing the first well for an additional period of ____________________by paying to the Lessor a rental of $________________per month for the first____________months of said additional period and $________________per month for the next__________months of said additional period, which said rental shall cease when drilling operations are commenced or the property quitclaimed.

10. The Lessee shall have the free use of so much of the oil, water or gas produced on said property as may be required in the operation of the property.

11. Other than the oil specified in paragraph 10 hereof, the Lessee shall pay as a rental or royalty for the use of said land one__________of all oil produced and saved thereon, said payment to be made in money or in kind at the Lessor's option. If the rental is paid in kind, the oil shall be delivered into tanks maintained on the property for that purpose as produced, and shall be stored at the Lessor's risk for a period not exceeding thirty days without charge. If the royalty is paid in money, then the

Lessee shall pay to the Lessor on the 20th day of each and every calendar month one__________of the market price at the well of all oil removed from said property during the preceding calendar month. The option to the Lessor to take the royalty in money or in kind shall only be exercised once every six months, and then on thirty days' notice in writing to the Lessee. If no notice is given, it shall be deemed that the royalties are payable in money.

12. The Lessee shall be under no obligation to store or sell gas or water. If any gas or water is sold, then on the 20th of each and every month, the Lessee shall pay to the Lessor one__________ of the proceeds of all gas or water sold during the preceding calendar month. If casing head gasoline is manufactured on the premises or elsewhere by the Lessee from gas produced in said wells, then the Lessee shall pay to the Lessor one__________of the proceeds of the sale of said gasoline, less the cost of producing and selling the same.

13. The Lessee shall pay all taxes on its improvements and__________of the increase of the taxes resulting from the discovery of oil on the said property, and of all oil stored on said land on the first Monday in March. The Lessee is hereby authorized to pay all the taxes on said land and improvements, and deduct the Lessor's share thereof from the amount of royalties which shall fall due.

14. All payments to the Lessor shall be made by paying the same to the__________ __________Bank at__________.

15. A well in paying quantities is hereby defined as a well which, after being pumped continuously for a period of thirty days, shall produce at least one hundred barrels of oil per day.

This definition shall not apply to wells to be operated on the expiration of the twenty year period or on the abandonment of a portion of the premises, and in such case, the Lessee may operate such wells as the Lessee in its discretion shall deem sufficiently productive to operate.

16. The Lessee shall carry on all operations in a careful, workmanlike manner, and in accordance with the laws of the State of California. The Lessee shall keep full records of the operations and of the production and sales of products from said property, and such records and the operations on the property shall be at all reasonable times open to the inspection of the Lessor. Whenever requested by the Lessor, the Lesse shall furnish to the Lessor a copy of the logs of all wells drilled on said property.

17. The Lessor shall have the right to the use of the surface of said land for agricultural and grazing purposes to such an extent as will not interfere with the proper operation of the Lessee for oil. The Lessee agrees to conduct its operations so as to interfere as little as is consistent with the economical operation of the property for oil with the use of the land for agriculural, horticultural or grazing purposes, and agrees to pay for any damage which may be done to growing crops or fruit trees through its negligence. If any of the fences existing on said lands are cut by the Lessee for its purposes, the Lessee shall establish a good and substantial gate at such point. Whenever required by the Lessor in writing, the Lessee shall fence all sump holes and other openings to safeguard cattle which may be grazing on said land.

18. The Lessor may have the use of any water or gas developed on said property for his domestic purposes, so long as the same is not required by the Lessee or sold. The transportation of such water or gas shall be taken at a point to be indicated by the Lessee and carried to the point of use at the cost and sole risk of the Lessor.

19. The Lessee shall have at any time the right to remove any houses, tanks, pipe lines, structures, casing or other equipment, appurtenances or appliances of any kind brought by it upon said land, whether affixed to the soil or not; provided, however, that in the case of an abandonment of any well, if the Lessor shall desire to retain the same as a water well, he may notify the Lessee to that effect and thereupon the Lessee shall leave such casing in the well as the Lessor shall require, and the Lessor shall pay to the Lessee fifty per cent (50%) of the cost of such casing in the ground.

20. In the event of any dispute as to any of the terms of this lease, or the performance of any of the conditions thereof by the Lessee, the same shall be submitted to arbitration. One arbitrator shall be appointed by each of the parties hereto, and a third arbitrator by the two so appointed. Any decision by a majority of such arbitrators shall be binding upon both parties

21. In the event of any breach of any of the terms or conditions of this lease by the Lessee, and the failure to remedy the same within sixty days after written notice from the Lessor so to do, then, at the option of he Lessor, this lease shall forthwith cease and determine, and all rights of the Lessee in and to said land be at an end.

22. Any notice from the Lessor to the Lessee may be given by sending the same by registered mail addressed to the Lessee at__________ and the Lessee or its successors or assigns may at any time, by written notice to the Lessor, change the place of giving notice, and after such written notice to the Lessor by registered mail, the Lessor shall send all notices intended for the Lessee or its successors or assigns, to the address which may be so indicated.

23. Any notices from the Lessee to the Lessor may be given by sending the same by registered mail addressed to the Lessor at__________.

24. All work done on the land by the Lessee shall be at the Lessee's sole cost and expense and the Lessee agrees to protect said land and the Lessor from claims of contractors, laborers or material men and the Lessor may post and keep posted on said lands such notices as he may desire in order to protect said lands against liens.

25. On the expiration of this lease, or sooner termination thereof, the Lessee shall quietly and peacefully surrender possession of the premises to the Lessor and deliver to him a good and sufficient quit claim deed and shall so far as possible cover all sump holes and excavations made by it and restore the land as nearly as possible to the condition in which it was received.

26. The Lessee agrees that no well shall be drilled within__________feet of any dwelling house now on said premises without the written consent of the Lessor.

This lease shall run to and be binding upon the successors and assigns of the parties hereto.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be executed the day and year first above written.

offer a higher royalty in lieu of a large bonus, since this arrangement reduces his preliminary outlay that is sacrified in case the property is unproductive. A one-eighth royalty, or 12½ per cent, is probably specified more frequently than any other, though one-tenth, one-fifth and one-quarter are also common; however, seldom more than one-fifth is offered by a careful leaser. The higher royalties lead to early abandonment of the property, for, as the production declines, the royalty payments rapidly diminish the profits. Because of this difficulty, many lessees advocate a sliding royalty in which the percentage paid decreases as the production declines. For example, it may be provided that for wells producing 25 bbl. per day, or less, a royalty of one-eighth will be paid; for wells producing from 25 to 100 bbl. per day, one-sixth; for 100- to 200-bbl. wells, a royalty of one-fifth; and for over 200 bbl., one-quarter.

For gas wells the royalty may be based on a percentage of the gross volume, as in the case of oil; though on account of the difficulty of metering the gas, many leases call for an annual rental ranging up to $150 per well. Cognizance may be taken in the lease of the added profit which results in extracting gasoline from natural gas, claiming a portion of such profit for the lessor.

Rentals are often inserted in leases, in addition to other considerations, as a means of preventing delay in development. It may be provided, for example, that until such time as a productive well or a specified number of wells are drilled, the lessee shall pay an annual rental of a stated amount per acre, often $1. In addition, the terms of the lease usually designate a time within which drilling must be commenced, and another time within which a well must be completed to a specified depth or stratigraphic horizon.

In return for the privilege of drilling and producing oil, the lessee is able to offer the landowner certain very definite and attractive inducements. In addition to a preliminary monetary consideration, the owner becomes a partner in the business with a preference right to a fair percentage of any profits that may result. His land is tested by the drilling of a well which costs him nothing, and he may prescribe conditions which will insure himself against damage or loss of any sort. He shares liberally in the profits, and risks nothing.

Leasing Practices.—The prospector must often obtain leases to several adjoining properties in order to secure sufficient territory to remunerate himself adequately in the event that his well is successful. In order to accomplish this without stimulating lease values by his efforts, the operator often adopts a secretive policy, perhaps acting through a local agent having the confidence of the people with whom he has to deal. This method is particularly common with some of the larger oil companies who often desire to keep their identity unknown until all necessary acreage is under lease. In many cases, certain landowners will refuse to

lease in the hope of securing more attractive terms in the event of oil discovery. Most of the larger oil companies have land and lease departments with certain officials employed whose duty it is to secure leases to such land as the geological department and the directing officials may designate as desirable.[1] With the smaller companies this work is often done by the field geologists. The larger companies also employ "scouts," often trained geologists or skilled "leasers," who maintain a close watch on the activity of other operators and on "wildcatting" and new development. Such men are often shrewd judges of property values and by prompt action secure choice acreage at favorable prices.

If a profit can be secured, a lease is often sold by the original lessee before a well is drilled. In fact, individual speculators sometimes secure leases during the early period of development of a new field, with the expectation of selling them to producing companies who are often too conservative to interest themselves in the more speculative aspects of the industry. In some cases, leases have changed hands several times before any drilling is done. The original lessee in selling his lease may secure a bonus greater than that which he paid for it, or retain an interest in the property as a partner or stockholder. Occasionally, an additional royalty payable to the original lessee may be exacted.

In a new field under active development there is also a considerable trade in lease royalties. The original property owner, anxious to realize on his expected profits, may be induced to sell his royalty interest for a sum which is sufficiently below the prospective income to form an attractive speculation for the buyer. Purchase of royalty interests by officials of the company owning the lease is quite common, though the ethics of such practice is sometimes questionable.

Legal Aspects of Oil- and Gas-land Leasing.—To be valid, a lease must be properly acknowledged and signed before a notary public or other authorized public official by both parties. If the property leased is a homestead and the owner is married, the wife's signature is also essential. The tract must be carefully described in the lease, if possible with reference to public land subdivisions, or by metes and bounds with reference to some definite landmark. As protection to the lessee against the possibility of the lessor dishonoring his agreement or issuing a second lease to another party, the instrument should be filed with the county recorder or county clerk.

The permanence of the lease is conditional upon the discovery of oil or gas in paying quantity; that is, the relation created is that of a conditional tenancy, but the discovery of oil or gas in the leased premises vests in the lessee the right to make future exploration, and to develop, produce and sell the mineral so discovered.[2] That is, after the discovery of oil, the lessee's right is no longer conditional, and the relation of landlord and tenant is created until the end of the term fixed by the lease. The

completion of an unsuccessful well does not necessarily terminate the lease, for it is ordinarily the obligation of the lessee and the right of the lessor that development shall continue. Though there may be a clause in the lease definitely limiting the duration in the event that a well is not drilled, or oil is not discovered, it is usually provided that if production is secured the lease shall continue as long as oil or gas is produced in paying quantities. In some leases, however, the period of production under the lease is limited by a definite number of years, always sufficient, however, to permit the lessee practically to exhaust the property.

It is usually provided that the lessee may surrender the lease at any time, if he so desires, and be relieved of any conditions to which it obligates him. Such surrender may require payment of a sum of money, however, if so stated as a condition in the lease. The lessor has no corresponding privilege of compelling a surrender unless the lessor defaults in some of the expressed terms. A lessee is not obligated to continue operation of a lease after it has become unprofitable to himself, though it may still be profitable to the lessor. It is only when manifestly fraudulent use of opportunities and control can be shown that courts are authorized to interfere between lessor and lessee.

Oil and gas leases frequently contain clauses designed to insure prompt commencement of drilling operations. Even in the absence of an expressed agreement, when a lessee undertakes to develop oil or gas on a rental or royalty basis, and the agreement does not specify the number of wells to be drilled, there is an implied obligation that the land will be fully developed with reasonable diligence. Under certain conditions, where a lease contains a provision permitting a lessee to pay a stipulated rental for delay in beginning drilling operations, the lessor may refuse to accept the rental and require the lessee to develop the property within a reasonable time or forfeit the lease. The phraseology of the lease has a determining influence on the right of the lessor in this connection. For example, in Oklahoma, if it is specified that a well is to be drilled within a certain time *unless* the lessee pays the lessor a stipulated rental, the lessee may terminate the lease by failure to pay rental; but the lessor may not do so as long as the rental is paid. If the word "or" is used instead of "unless," the lease is not necessarily terminated unless the lessor claims the forfeiture.[1]

If a lease is assigned by the lessee to another for a valuable consideration, the assignee legally assumes all of the conditions, implied or expressed, and is liable for all obligations maturing during his tenancy.

To be legal, a lease must possess "mutuality." In several instances where leases have provided for no bonus, and where no obligation to pay any penalty for surrender of the lease is expressed, it has been held by the courts that the arrangement was terminable at the pleasure of either party. The question of whether or not some nominal sum, such as $1,

is a sufficient consideration to support a lease of this character has led to diverse opinions in different jurisdictions.

In the absence of contrary expression in the lease, the lessee has only such rights to the surface of the leased land as may be necessary to the exercise of his right to extract the oil and gas. He must give adequate protection to the lessor's property and is liable for damages if he fails to do so. Where the lessee has in part developed a property held under lease by the drilling of productive wells and has failed to offset wells on neighboring properties to prevent drainage, the lessor may secure damages from the lessee in lieu of the additional royalties that he would otherwise receive; but if no wells have been drilled on the premises the lessor has no recourse beyond the time limits set by the lease for the drilling of the initial well.

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CHAPTER IV

DEVELOPING THE FIELD

Once the existence of an oil field has been proved by the drilling of a commercially productive well, interest at once centers on the problem of determining the extent of the field, that is, the area within which production will be obtained and the position of the more productive sections. Knowing that a given area will be productive, the property owner within that area is then confronted with the problem of planning a development campaign with respect to definite boundary lines, which will adequately protect his property against the activity of neighboring operators and which will result in the maximum profit being obtained from the land. The planning of the development program involves careful consideration of a number of interrelated factors, among which are the spacing and arrangement of wells and the economic rate of development as influenced by the cost of drilling, the probable future selling price of oil, the capital cost of the land and its equipment, the productivity and rate of decline of the wells and the interest rate to be demanded on the investment.

EXPLORATION: DETERMINING THE LIMITS OF THE FIELD

The discovery well proves that oil is present in commercial amounts and gives important information concerning the sequence and nature of strata penetrated and the horizon in which the oil is found. The possibility of obtaining production from areas about the initial well will be a matter of conjecture until additional wells can be drilled, though if it is possible to work out the geologic structure from surface evidence and determine the direction of the major axis of the fold in which the oil has accumulated, the geologist may predict the most favorable direction from the discovery well for further development. The type of structure, the magnitude and extent of the fold and the dip of its flanks and axial line will be important considerations in determining the position of second, third and later test wells and the distance at which they may be spaced from the discovery well. Usually the operator will be anxious to "prove" the largest possible area with the fewest number of wells, yet without running the risk of locating a well beyond the limits of the pool and drilling a "dry hole."

If the structure indicates a well-developed anticline or dome, exploration for the limits of the productive area may be conducted by drilling wells first in both directions along the major axis of the structure, locating

the wells as nearly as possible along the structural crest, and secondly along a line at right angles to the axis, locating wells alternately on either side of the crest, thus exploring down the flanks until edge water is encountered or until the wells become such small producers that they cease to be profitable. If the logs of these wells are carefully preserved, it should be possible, from a study of the results recorded, to gain a fair impression of the disposition of the producing oil sand or zone and perhaps even to draw a rough structure contour map of its top surface (see Fig. 18). Later drilling along other lines at right angles to the major axis may disclose local variations in dip and thickness of the oil-bearing strata,

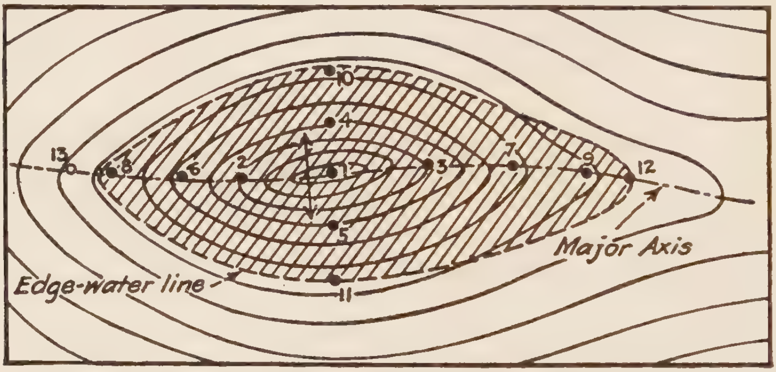


FIG. 18.—A structure contour map showing location of test wells on dome structure to determine the productive limits of a new field.
Hachuring shows productive area.

but such changes will not greatly alter the extent of the productive area as determined from the data accumulated and applied as described.

If the structure is monoclinal, it will usually be possible to locate the outcrop definitely and, by measuring its dip at various points, to determine very closely the depth to the productive stratum at any location. Usually the first test wells will be drilled near the outcrop so that the wells are shallow, and yet they should be located far enough down-dip to avoid the zone of surface influence near the outcrop. Oils near the outcrop are often heavy and viscous by reason of seepage and evaporation losses of the lighter constituents at the surface and do not give a fair test of the capabilities of the structure. Exploration will be conducted along lines at right angles to the strike, locating wells to penetrate the producing zone at successively greater depths until the lower limits of the pool are encountered.

Factors Influencing Productivity and Form of the Field

From the foregoing it will be observed that location of wells in the development of an oil field is based primarily upon geologic considerations. While extensions of the field from a discovery well may be pre-

dicted on the evidence of structure, the form of the field and productivity of different portions of it will be largely influenced by minor changes in dip or hade of the structure and by lithological variations in the productive strata.

The Influence of Dip and Hade of Structure.—A steeply dipping anticlinal formation would indicate a narrow productive area—perhaps a long narrow strip of territory along the structural crest. Plunging of the axis at either end of an anticlinal structure would definitely limit the productive area in the direction of the strike. The extent of a field located on dome structure would be greatest in the direction of the lowest dips and relatively narrow in the direction of steep dips. A symmetrical dome with strata dipping at the same angle in all directions is rare in nature. The major structure is often influenced by intersection with minor folds. Two intersecting anticlines may result in forking of the productive area or a local windening of the field. Wells located at such intersections also are likely to be more productive than elsewhere since anticlinal intersections cause doming, with resultant concentration from all directions instead of two. A change in the direction of strike of an anticlinal fold is regarded as favorable to local concentration and high productivity of wells, since here also the lines of oil migration up the dip are brought to a focus, particularly on the convex side of the fold. Though local variations of this character are of importance in selecting the more valuable areas within a field, it must be recognized that the extent and continuity of the field as a whole are dependent on persistence of structure and maintenance of an approximately level axis.

The Influence of Lithological and Stratigraphical Variation.—The shape of the field and the productivity of areas within it will be greatly influenced by changes in the porosity and thickness of the oil-bearing strata. Variation in porosity, if extreme, will result in highly productive lenticular pools surrounded by almost barren areas, though the major concentration may have been effected by a well-defined anticlinal structure embracing both the productive and non-productive areas. The more porous rocks will naturally give the higher initial yields, and wells drilled into thick oil sands will be more productive than those deriving their oil from thinner strata. Variation in the thickness of an oil-producing stratum will thus cause great irregularity in property values. Local "pinching out" of a productive sand may result in an area within the heart of a producing field being practically barren.

The extent of the field and the productivity of different portions will also be influenced by the number of oil-bearing strata occurring beneath it. It often happens that there will be several well-defined oil sands, separated from each other perhaps by several hundred feet or more. In such cases the lower strata are often less influenced by the structure, that is, they dip at lower angles and the productive area will be wider. Pro-

ductive lower zone wells may thus penetrate the upper zone beyond its productive limits. Then too, if the fold is asymmetric, the axis of a lower sand will not conform with that of an upper sand, so that the more productive first-zone wells may be less advantageously located with respect to the lower zone (see Fig. 2).

Correlation of Well Log Data.—Even though competent geologic advice is to be had, the early period of development in a new field will often be one of great uncertainty. Perhaps a number of operators will be in competition with each other for early production and efforts are chiefly directed toward speed in drilling instead of to the important work of securing accurate well log data to aid in correlating and interpreting structural conditions. Many operators consider their well logs as confidential information, so that it becomes a difficult matter for one interested in working out the structural and stratigraphic relationships to secure the necessary data. It is to the mutual advantage of all operators in the field that all available subsurface information be freely exchanged in order that the structural and stratigraphic features may be worked out at the earliest possible time.

Operators in a new field should make an effort to reach a common understanding on the names and characteristics of the more important strata penetrated by the wells so that there will be some degree of uniformity in the well log data accumulated. If there are any persistent strata of striking characteristics that might serve as marker horizons for correlation and reference, these should receive particular attention.

If the well log data are accurate, a peg model* will display the general trend of the structure as soon as a few wells have been completed, and, as more pegs are added, the local dips and irregularities will become apparent. Often local irregularities in depth to production, or dry holes drilled in locations thought to be productive, will cause confusion during the early period of development, and if there are several oil sands within a productive zone, as is often the case, variations in the productive area covered by the different sands may further complicate the problem. Often the position of "water sands" will be uncertain, and irregularities in the position of "water shut-offs" and landing depths for casings in near-by wells will allow water to enter the oil sands at certain points to the detriment of oil production. Obviously, accurate well logs should be the primary consideration during the early period of development, in order that these irregularities may be fully understood and a uniform system of casing wells and excluding water determined upon.

If the ordinary rock characteristics are not sufficiently distinctive to furnish a means of correlating strata from well to well, a closer study of formation samples from a few wells that have been carefully drilled and systematically sampled will usually disclose certain peculiarities that

* For a description of the methods of constructing peg models, see Chap. XII.

characterize one or more of the persistent strata. A particular sand may contain an unusual percentage of some distinctively colored or crystallized mineral, such as hornblende or biotite or olivine, or the sand grains may be unusually coarse- or fine-, or even-textured. Another may contain a particular type of foraminifera or other fossil indicator. The water contained within a water sand may have unusual chemical properties. Often, if there is more than one oil sand, the oil will differ somewhat in gravity in the different strata. Some of these are properties which will require skilled technical assistance in identification, but if such a relationship is once established it will serve as a useful means of correlation, perhaps throughout the entire field. Local irregularities or erroneous log data may by such means be readily adjusted to the established markers and stratigraphical correlation completely established.

PLANNING THE DEVELOPMENT PROGRAM

Unfortunately, the average operator is seldom in control of the entire area within a producing structure. Ordinarily several, or perhaps many, independent operators will own different portions of the field and will enter into competition with each other for production. All produce from what is, in effect, a common reservoir, and the activities of one operator will directly influence the ultimate recovery to be effected from neighboring properties. Location of the early wells in undeveloped territory will therefore be influenced by property lines as well as by geologic structure and local lithological variations; indeed, protection of property lines is often given the greater consideration.

Influence of Neighboring Activity on the Development Program

With the idea of preventing drainage across property lines, it is customary to drill the "outside locations" along boundaries, before the interior locations are drilled. Often the first wells on a property will be placed in the corner locations, thus protecting against drainage by corner wells in the three adjoining properties. The side boundary wells will next receive attention, no interior locations being drilled until all of the line wells have been completed.

This program assumes that all surrounding operators are equally active. If all neighboring activity should be concentrated on one side of a lease, the boundary wells on that side would be first drilled and perhaps one or two rows of interior wells will also be drilled on that side of the property before attention is given to the other wells along boundaries where competition is not keen. If a property is located on the edge of a producing field, it may be that production on the side nearest the field will be practically certain, while the possibility of obtaining oil in wells drilled along the far side (usually the down-dip side) will be more or less problematical. In such a case, in order to avoid the loss occasioned by

the drilling of dry holes, development may proceed progressively down-dip from the boundary nearest neighboring producing wells, the down-dip boundary locations not being drilled until it is fairly certain that they will be profitable producers.

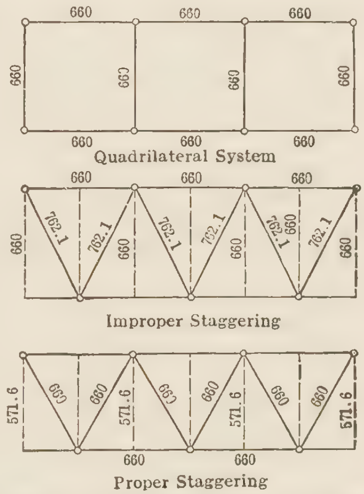
The planning of a development campaign with respect to neighboring activities has both defensive and offensive aspects. The operator who first brings his property to full development will secure more of his neighbors' oil than they are able to secure of his. Closely spaced wells and wells of large diameter will drain an area more rapidly and thoroughly than a fewer number of small wells. Then, too, the early wells in an undeveloped area will usually have the greater ultimate productions. Initial productions are higher because of greater gas pressure during the early stages of development, and the earlier wells seem to maintain their superiority in later years, possibly by establishing drainage channels during the early period before interference by later drilled wells becomes a factor of importance.

Offsetting and Line Agreements

As a measure of protection against drainage across property lines, it has become customary for adjoining property owners to place their line wells directly opposite each other (that is, on a line at right angles to the boundary line) and at an equal distance from the boundary line, a practice known as "offsetting." If operator A drills eight wells spaced 660 ft. apart and 100 ft. back from the line along his west boundary, operator B, owning land on this side, must drill as many wells similarly spaced along his east boundary, otherwise A gains the advantage in production from the line wells. This advantage can actually be translated into terms of equivalent acreage. The obvious disadvantage to all parties concerned, of adjoining operators entering into "boundary warfare" through competition in the drilling of line wells, has led in many instances to formal agreements not to drill more than a stated number of wells along the common boundary and to drill not closer than a specified distance from it. Such regulations are sometimes tacitly accepted by all the operators of a field or district, so that the spacing of wells along boundaries is approximately uniform throughout the field. For example, in the California fields wells are often placed either 100 or 150 ft. back from the line. Spacing along the line will vary in different localities with the prevailing opinion concerning the number of wells necessary to drain the land completely within a reasonable space of time. While defensive considerations would dictate the drilling of offset wells along boundary lines directly opposite each other, less interference results when locations on opposite sides of the line are staggered. This, too, might be accomplished by mutual agreement.

Arrangement of Wells

Some geometric pattern is usually followed in the location of interior wells, arranging them in rows across the property and spacing them equally apart so that all sections are equitably drained. A rectangular arrangement is often followed, but a triangular pattern[2] in which the wells in adjacent rows are staggered gives more complete drainage (see Fig. 19). There is some justification for spacing the wells nearer together in the direction of the strike of the formation than in the direction of its dip. If it be assumed that the movement of oil is primarily up the dip of the structure, the operator should strive to place a screen of closely spaced wells across the direction of flow, while in the direction of dip they need not be so closely spaced. Theoretically, a single row of closely spaced wells along the crest of a level anticline will completely drain it, the oil migrating under the influence of hydrostatic pressure directly up the dip of the structure. However, if the flow be considered as due chiefly to gas pressure, which is equal in all directions, the dip of the formation will have little significance. If we assume that drainage is due entirely to gas pressure, the wells in steeply dipping strata should be logically placed nearer together in the direction of dip than in the direction of strike. This follows from the fact that the well intersections with the producing sand are farther apart as measured in the plane of the dip than they would be with reference to a horizontal plane.



(*After R. H. Johnson, in Trans., Am. Inst. Mining Met. Eng.*)

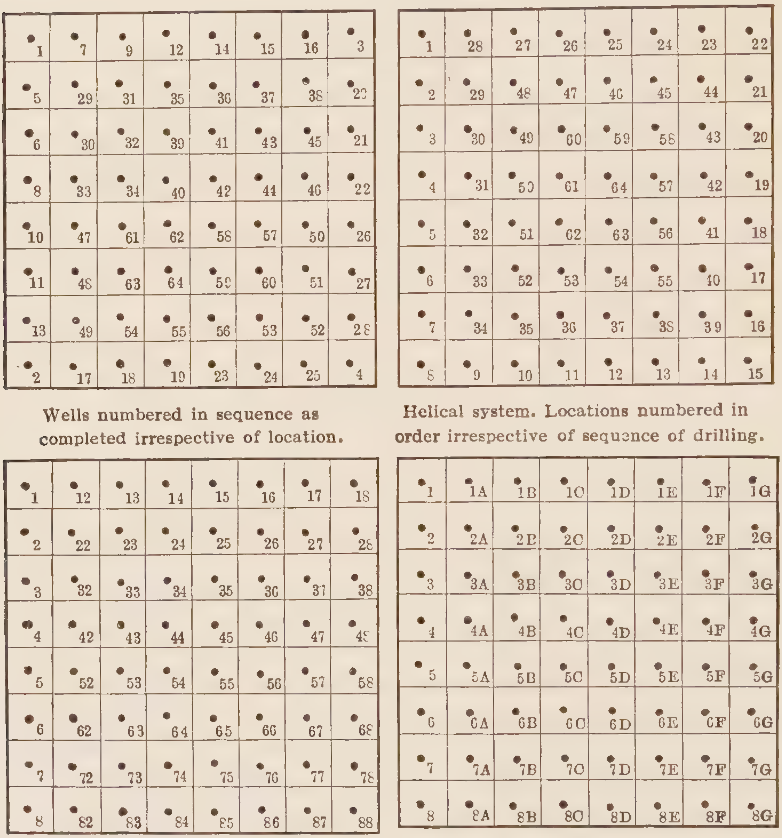
Fig. 19.—Illustrating rectangular and triangular systems of well spacing.

Often the spacing and arrangement of the boundary wells will determine the position of interior wells, particularly if the property is a small one. There is better opportunity for scientific well spacing and arrangement when land is held in large tracts than when small acreages are the rule. Town lot drilling in some of our western American fields, with resultant overcrowding of wells and unequal spacing, has resulted in great economic waste, and, in many cases, owing to overdrilling and mutual interference, operations have been unprofitable.

Numbering of Wells

It is customary to number the wells on each property, for convenience in reference, in the order in which they are drilled (see Fig. 20). An

alternative plan, one followed by some of the larger oil companies operating many different properties, is to number the wells with reference to their position and irrespective of the order of drilling. One becoming familiar with such a system knows at once, from the well number, its



Wells numbered in sequence as completed irrespective of location.

Helical system. Locations numbered in order irrespective of sequence of drilling.

Coördinate system. Locations numbered in order irrespective of sequence of drilling.

Coördinate system using figures and letters.

FIG. 20.—Systems of numbering oil wells.

position on the property, but the well numbers would not indicate their relative ages.

RATE AND ORDER OF DRILLING

It is apparent that if we hurriedly bring an oil property to full development, we shall have a rapidly increasing daily production which reaches a peak rather early in the life of the property and then gradually declines as the productivity of the wells decreases, until, during the later years of the productive life of the property, the daily production reaches a

comparatively low figure (see upper graphs, Fig. 21). This plan of development probably results in the greatest ultimate production, but it has the disadvantage that the drilling, production, storage and transportation facilities are greatly overtaxed during the early years, usually necessitating equipment of the property on a scale far in excess of what is required during the later years. Furthermore, when this plan of development is followed there is some possibility, in restricted markets, of over-

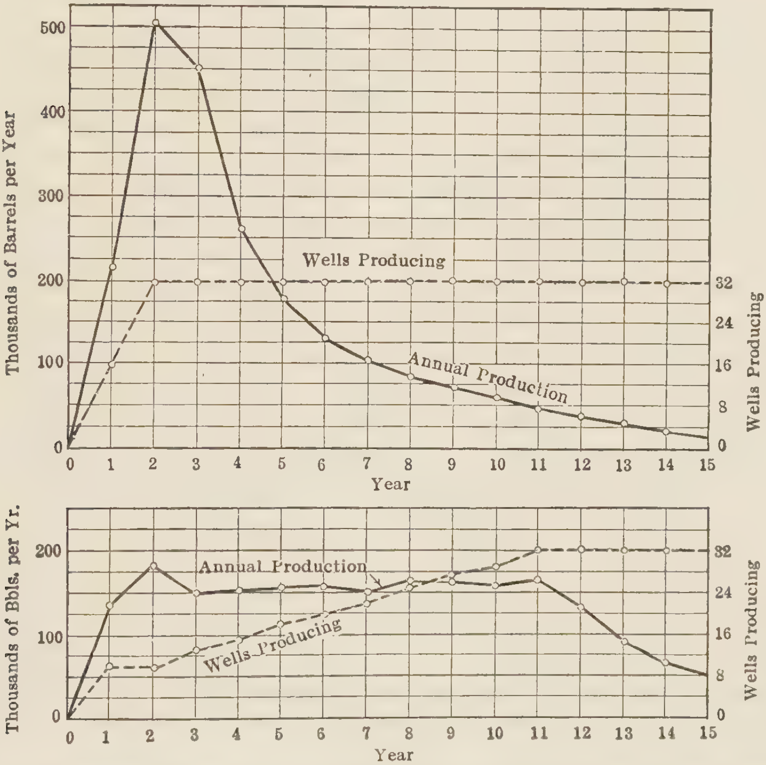


Fig. 21.—Estimated production of an oil property with rapid development (upper graphs), and with slow development planned to maintain uniform output (lower graphs).

Note that in each case wells are assumed to be so spaced that they have equivalent initial productions and decline rates.

production during the early period, which reacts to depress prices, so that the gross returns will be somewhat reduced by a lower average selling price per barrel of oil.

While the maximum amount of oil is secured by drilling all of the wells at once, such a program is often impracticable since the drilling of a large tract must necessarily extend over a number of years. The physical difficulties of road building, rig construction, securing and distributing water supply, camp construction, etc., must precede drilling. The cost of duplication of well-drilling equipment necessary for an

intensive drilling program and the provision of working capital for the drilling of many wells at the outset of operations are often prohibitive. The producer usually finds it expedient to finance a part of the cost of developing the property from its production; hence a few wells are drilled first and placed on production and new wells are added as rapidly as finances and working conditions permit.

Most operators prefer to bring the production rapidly up to a predetermined daily production which will provide a suitable return on the investment and then discontinue further drilling until such time as the wells begin to decline. Thereafter, new wells will be drilled at a rate just sufficient to maintain the production at the desired level (see lower graphs, Fig. 21). This plan results in a uniform rate of production throughout the greater part of the life of the property, and the disadvantages of an intensive preliminary development campaign are largely eliminated.

The development of an oil property may be conducted according to either of several plans. A common method is that of drilling rows of wells, blanket fashion, across the property from proven territory to unproven territory. This plan gives maximum insurance against the drilling of dry holes when it is not certain that the entire area beneath the property is productive. It also offers opportunity for securing necessary information on structural and subsurface conditions for new locations before drilling is begun; that is, geological surmise, based on data from wells only one row distant, is relatively certain in comparison with estimates projected to remote locations in untested territory. A somewhat similar plan is that of drilling progressively outward from productive test wells as centers.[3]

Another method of development involves the preliminary drilling of widely scattered wells at some uniform spacing (say 15 to 30 acres per well); then, after this primary system of wells has been completed, intermediate wells are drilled at a smaller interval calculated to give the most economic extraction. This plan has three distinct advantages: (1) the initial productions of scattered wells are, as a rule, considerably higher than those attained by the usual spacing; (2) production from widely spaced wells is better sustained than that from wells closely spaced; (3) final decision as to the ultimate spacing and disposition of wells can be deferred until fairly complete information is available on which to base computations of economic spacing. However, the secondary system of intermediate wells will be deprived of the higher gas pressures and will be relatively small producers, owing to deferment of the period of drilling and interference from the primary wells. The ultimate production per acre is therefore lower when this plan is followed. It is evident, however, that early wells in isolated positions having relatively high initial productions followed by several years of sustained production will during these years yield to the producer greater and quicker returns than would the

same number of closely spaced wells which are as expensive to drill yet have a lower average yearly production. The loss in ultimate recovery of oil may therefore be compensated by the earlier return on the investment, elimination of the possibility of drilling too closely and a better final spacing of the wells based on production data from the primary wells.

Examples illustrating the greater productivity of widely spaced, isolated wells may be found in every oil field, but the following data given by Cutler[3] are representative:

> During the 5-year period, 1913 to 1917, the average yearly initial production of 24 isolated wells in the Buena Vista Hills area, California, was 260,000 bbl., while during the same period that of 104 offset wells was 172,000 bbl. per year; that is, the initial productions were 50 per cent greater for isolated wells than for closely spaced wells. If we assume a drilling campaign which would permit isolated wells to produce 3 years before being offset, the average isolated well, having an initial yearly production of 260,000 bbl., will produce 567,000 bbl. according to actual production records. During the same 3-year period, the average offset well with an initial yearly production of 172,000 bbl. will produce only 345,000 bbl., showing a gain for the isolated well of 222,000 bbl. This indicates the gain in immediate recovery due to isolation in the Buena Vista Hills area.

The production decline of widely spaced wells is accelerated when their drainage areas are encroached upon by interspaced wells. Hence, the benefit to be derived by drilling scattered wells is negligible if it is followed by rapid drilling of interspaced wells.

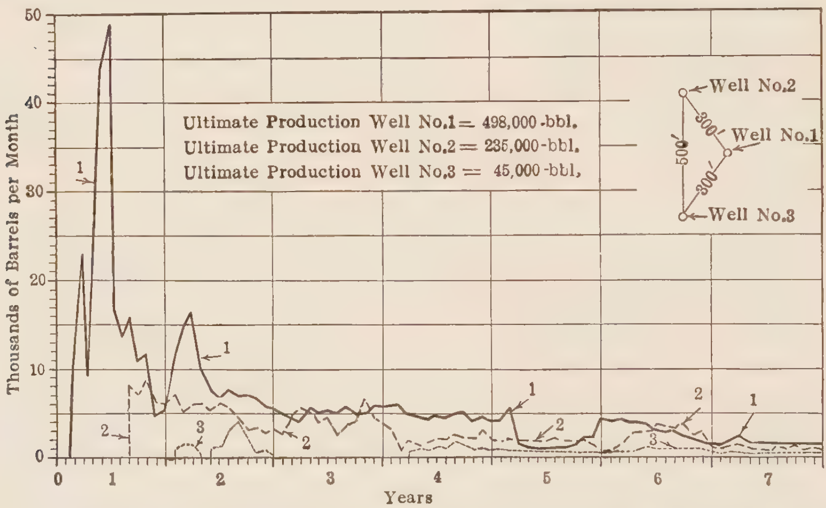
Importance of Timely Development

Maximum ultimate recovery of petroleum from an oil field is secured by systematic and timely drilling of wells, thus deriving the greatest benefit from the relatively high initial gas pressure. Natural gas, dissolved and occluded in the oil under pressure, is the principal motivating agent causing the oil to flow from the reservoir rock into the wells during the early life of most oil fields. Productivity of the wells diminishes as the gas pressure declines. Maximum field pressures are experienced only in wells drilled during the early life of a field. Escape of gas through these early wells leads to rapid decline of field pressure so that later drilled wells have smaller initial and ultimate productions. The oil that these later drilled wells fail to produce, in comparison with the recoveries effected by the earlier wells, is largely left in the sands, drained of its gas and unrecoverable by ordinary flowing and pumping methods. If all the wells could be completed in time to receive the benefit of the higher field pressures, greater recoveries would unquestionably result.

Maximum recovery of oil from a pool requires prompt and complete development of the entire oil-bearing area, once the discovery well has entered upon its productive life, and in areas where there has been

considerable delay we may expect to find an important supply of residual oil. The operator who fails to maintain the pace set by his neighbors, or who is unable to finance the rapid development of his property, not only loses some of his oil to his more active neighbors but also ultimately leaves oil in the ground which neither he nor his neighbors can secure, that is, oil that is left in the productive formation gas drained and without motivating force to bring it into the wells. The oil producer who merely protects his boundaries by offsetting neighboring line wells, leaving his interior locations to be drilled in later years, likewise suffers a loss of a large part of the potential production that his wells might have secured had the entire property been fully developed at an earlier date.*

Field Studies of Losses Resulting from Delayed Development.—In connection with litigation incidental to the efforts of the U. S. Government to clear land titles in the California naval oil reserves and on lands withdrawn from entry pending passage



After J. H. G. Wolf.)

FIG. 22.—Production graphs of three contiguous wells in the Midway field, California, illustrating advantage of securing early production in an undrilled area.

of the Mineral Land Leasing Law of 1920, studies were made of the production records of several hundred wells in an effort to determine their radius of influence and the losses resulting from delayed development. The results of this study were made public in 1924 by the Committee on Public Lands of the U. S. Senate. In this investigation, interest was centered upon small groups of wells and offset couples one or two "locations" apart, in order to secure approximately uniform conditions permitting of legitimate comparison of production records. In some instances the production records of individual wells were available, offering a means of comparing the decline characteristics of wells in "influenced" and "uninfluenced" territory. Complete well logs and histories were also provided, and, in the comparisons made, the only records used were those in which the productive sands were well defined and appar-

* UREN, L. C., Influence of Delayed Development on Ultimate Recovery, *Nat. Petroleum News*, Oct. 2, 1929, pp. 65–72.

ently continuous and the source of the oil was definitely known. In each case the ultimate productions of the wells were estimated by the production-decline-curve method.

The greater recoveries secured from the earlier drilled wells stand out in striking contrast with the relatively small recoveries obtained from later drilled wells. For example, in Fig. 22, well No. 1 was drilled 7 months before No. 2, and No. 3, 5 months later than No. 2. Well No. 1 will ultimately produce 2.12 times as much oil as No. 2 and more than 11 times as much as No. 3. This group of wells is typical of many others that were examined in the course of the field studies. Areas in two different fields were included in the investigation. While the results were widely variable when wells producing under different conditions were compared, the data are sufficiently similar to permit of drawing certain general conclusions which, it is thought, represent the results to be expected under average conditions in the Coalinga and Midway

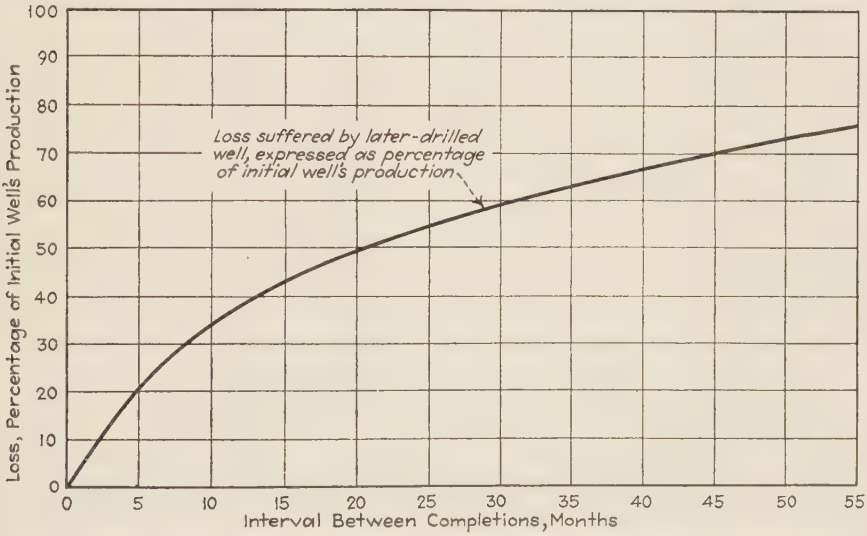


FIG. 23.—Graph showing average difference in production between offset couples for varying time intervals between completions, Coalinga and Midway fields, California.

fields of California. Fig. 23 shows the average loss of a later drilled well for varying intervals of time between completions of earlier drilled and later drilled wells. The graph indicates, for example, that if a well is drilled within gas-drainage radius of another well and is drilled, say, 20 months later, it will produce only 50 per cent as much oil; and if drilled 45 months later, it will produce only 30 per cent as much oil as the earlier drilled well. The production records used in compiling the data for this graph were computed over a period of 6 years of simultaneous production, that is, for 6 years following the completion of the second well. It will be understood that the data of Fig. 23 are not quantitatively applicable to other dissimilar fields, though the general conclusions reached are of broad application. In other fields, where the productive sands may be thicker and of different texture, or where the initial gas pressure and viscosity of the oil vary materially from those prevailing in the fields in which the studies were made, we should expect a different loss ratio. The results clearly indicate the importance of timely drilling and serve to give a quantitative impression of the magnitude of losses resulting from failure to achieve timeliness and uniformity in field development. They also suggest a possible method of analysis in making estimates of residual oil content of partially depleted oil lands.

Spacing of Oil Wells

One of the most important problems confronting the owner of undeveloped oil-producing acreage is that of determining the number of wells to be drilled on the property to realize maximum profit. For any set of conditions, there must always be a definite number of wells which will exploit a given area most profitably. There is a relationship that exists between the cost of drilling the wells, the volume and value of their ultimate production and the productive life period, which determines how many wells should be drilled. Within certain limits the greater the number of wells provided, the greater will be the gross production and the more rapidly will it be secured. This means greater revenue. On the other hand, the greater the number of wells drilled, the greater will be the development and lifting cost. Though overhead expense may be spread over a greater production when a large production is realized, development and lifting expense are items of much greater magnitude; hence, beyond a certain point, unit production costs increase as the number of wells is increased. Well spacing is not so much a problem of determining how many acres a well will drain as it is a problem of determining the number of wells that will realize maximum profit to the producer.

Because of the great number and complexity of the variables that enter into this problem of determining the economic number of wells, most oil producers have been content to follow precedent, adopting some arbitrarily conceived spacing program that no doubt has in many cases resulted in lower profits than might otherwise have been realized. The development program is often dictated by some ill-advised neighboring operator, competitive considerations replacing scientific and economic drainage principles.

In most fields custom has decreed a certain spacing of wells, or the allowance of a certain drainage area per well, but investigation will show that in practically every case, in fixing the interval between wells, operators have merely followed a practice with which they had become familiar in other fields or districts. A common interval between wells in many fields for example is 660 ft., but this merely resulted from the fact that one well in the center of each 10-acre tract provided such spacing, and 10-acre tracts are convenient units in buying and leasing land. If proper consideration is given to drainage principles and economic factors, this interval might be appropriate in some cases but will be grossly in error in others. Casual inspection of the property maps in almost any oil field will show that the average oil producer gives but little attention to this all-important problem. Apparently he knows but little more about scientific well spacing today than did the pioneers of the industry two generations ago.

Factors Governing Economic Spacing of Wells.—Among the physical variables influencing the economic spacing of wells, it is clear that the sand permeability and reservoir pressure under which the oil is stored are important considerations. The more permeable the reservoir rock and the higher the field pressure, the more widely spaced may the wells be to achieve a desired percentage recovery. The thickness and porosity of the reservoir rock are important in determining its storage capacity. The thicker and more porous sands yield more oil and therefore support a greater number of wells. Another important physical factor is found in the diameter of the well through the reservoir rock. The larger the bore of the well, the more effective will it be in securing high-percentage recovery of the drainable oil. Hence, large-diameter wells may be more widely spaced for the same drainage effect. If, on the other hand, the primary interest is the "pay-out status," large-diameter wells may be more closely spaced. Consideration must be given to the position on structure in determining a suitable spacing for wells. Those near the crest of a well-developed anticlinal or domal structure have the advantage of greater gas energy in expulsion of oil from the reservoir rock and therefore secure a greater percentage of the drainable oil than is possible from down-dip locations where gas is less plentiful. Wells may be more closely spaced on the structural crest and yet pay out. Movement of gas is preferably up the dip of the formation; hence, in so far as expulsion of oil by gas is concerned, oil migration is also accomplished with greatest facility in this direction. It would therefore appear that for uniform recovery wells should be more closely spaced in the direction of the strike of the formation than in the direction of the dip.[13]

Economic factors are equally important in determining the number of wells that may be profitably drilled on a given tract of land. The cost of drilling and equipping wells increases rapidly with depth, and the cost per foot varies with the character of the formation penetrated. It follows that where the wells must be deep or the formations are unusually costly to drill, wells must be more widely spaced if they are to be profitable. The unit-production cost, as influenced by the depth of the wells and rate of production, will also be important in determining economic well spacing. Lower unit production costs will permit of closer well spacing. Furthermore, the selling price of the product is a factor of importance. If the oil is of high quality or if, for competitive reasons, it commands a good price, the wells may be more closely spaced than in fields where the oil prices are low. The interest-earning capacity of invested capital has its influence on well spacing in diminishing the present value of future profits, thus increasing the incentive for prompt realization on invested capital. This would be promoted by close spacing of wells.*

Well-spacing Formulas.—The many different variables involved in the well-spacing problem and the intangible nature of some of them have made the development of an all-inclusive formula exceedingly difficult. Several authors have offered formulas that are useful to a certain extent in analyzing the results of different well spacings in fields where development has proceeded to a point that will permit of determining ultimate recoveries and of estimating what might have resulted had a different spacing program been adopted.[5,6,9] What is needed, however, is a formula that will permit of predicting proper spacing in advance of development. Determination of the economic interval between wells in reality presents a group of related problems some of which are not susceptible of accurate analysis with data now available. This being true, we can at present only approach a general solution by a series of approximations. Though a general well-spacing formula is apparently not attainable in the light of our present knowledge, it should nevertheless be eventually possible to formulate the many influencing factors along mathematical lines.†

* Uren, L. C., Factors Governing Economic Spacing of Wells, *Nat. Petroleum News*, Nov. 27, 1929, pp. 59–66.

† Uren, L. C., Theoretical Aspects of Well Spacing, *Nat. Petroleum News*, Jan. 1, 1930, pp. 49–58.

Field Data on Influence of Well Spacing on Ultimate Recovery.—[illegible]

TABLE VII.—EFFECT OF SPACING OF WELLS ON ULTIMATE PRODUCTION [illegible]

Spacing, acres per well	Initial year's production, bbl.	Ultimate production per well, bbl.	Ratio of ultimate productions per well, per cent	Ratio of square roots of areas drained, per cent	Ultimate production per acre, bbl.
[illegible]	6,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	6,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	6,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	4,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	4,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	4,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2,000	[illegible]	[illegible]	[illegible]	[illegible]

TABLE VIII.—EFFECT OF WELL SPACING ON ULTIMATE PRODUCTION [illegible]

Spacing, acres per well	Initial year's production, bbl.	Ultimate production per well, bbl.	Ratio of ultimate productions per well, per cent	Ratio of square roots of areas drained, per cent	Ultimate production per acre, bbl.
[illegible]	4,000	[illegible]			[illegible]
[illegible]	4,000	[illegible]			[illegible]
[illegible]	4,000	[illegible]	100	100	[illegible]
[illegible]	4,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	4,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2,000	[illegible]			[illegible]
[illegible]	2,000	[illegible]			[illegible]
[illegible]	2,000	[illegible]	100	100	[illegible]
[illegible]	2,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	1,000	[illegible]			[illegible]
[illegible]	1,000	[illegible]			[illegible]
[illegible]	1,000	[illegible]	100	100	[illegible]
[illegible]	1,000	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	1,000	[illegible]	[illegible]	[illegible]	[illegible]

Mid-Continent, Appalachian and California fields, all of which indicate that close spacing of wells is productive of greater per acre recovery, though the greatest per well production is secured by wide spacing.

W. W. Cutler, Jr., has assembled data illustrating the effect of well spacing on recovery efficiency in several Oklahoma fields.[3] Table VII gives the results of a study of production data from 134 wells on 23 different tracts in the Nowata district, northern Oklahoma, in areas where three different spacings were used and a considerable variation in initial production of wells was experienced. Table VIII gives similar data for 337 wells on 80 different tracts in the Bartlesville-Dewey district of northern Oklahoma. Results for five different spacings are available here. Cutler has also assembled similar information on 10 tracts with 114 wells on two different spacings in the Speechley Pool, Butler County, Pa., as reproduced in Table IX. The

TABLE IX.—EFFECT OF WELL SPACING ON ULTIMATE PRODUCTION IN THE SPEECHLEY POOL, PENNSYLVANIA

Spacing, acres per well	Initial year's production, bbl.	Ultimate production per well, bbl.	Ratio of ultimate productions per well, per cent	Ratio of square roots of areas drained, per cent	Ultimate production per acre, bbl.
10	1,600	9,300	100	100	930
6	1,600	7,850	83	78	1,308
10	1,000	6,500	100	100	650
6	1,000	5,600	86	78	933
10	800	5,400	100	100	540
6	800	4,800	89	78	800

TABLE X.—EFFECT OF WELL SPACING ON ULTIMATE PRODUCTION IN THE MEYER ZONE, SANTA FE SPRINGS FIELD, CALIFORNIA

Spacing, acres per well	Ultimate production per well, bbl.	Ratio of ultimate productions per well, per cent	Ratio of square roots of areas drained, per cent	Ultimate production per acre, bbl.
4.35	424,000	100	100	97,500
0.66	322,500	76	39	492,200

data presented in these tables are arranged to demonstrate a theory advanced by Cutler, in which he states that: "The ultimate productions for wells of equal size in the same pool, where there is interference, seem approximately to vary directly as the square roots of the areas drained by the wells." The rule may also be stated thus: "The recovery from wells of equal size, producing under similar conditions in the same pool, is proportional to the average distance that the oil moves to get to the well." This theorem seems to rest upon a fundamental law of hydraulics which states that the energy required to move a fluid is directly proportional to the distance moved; *i.e.*, if we double the spacing between wells, still utilizing the same energy, we secure only half the recovery. While Cutler's theorem apparently holds for normal intervals between wells, he expresses some doubt concerning its application in very close

spacing—as in certain "town-lot" fields—other considerations, such as a greater tendency of gas to by-pass the oil in the sand, influencing the result to an important degree when the wells are very closely spaced.

TABLE XI.—COMPARISON OF RESULTS FOR WIDE AND CLOSE SPACING OF WELLS IN THE LONG BEACH FIELD, CALIFORNIA

Spacing, acres per well	Recovery per well to July 1, 1929, bbl.	Ratio of productions per well, per cent	Ratio of square roots of areas drained, per cent	Total production per acre to July 1, 1929, bbl.
2.92	266,569	100	100	91,395
0.71	140,399	53	49	196,558
3.23	231,638	100	100	69,990
0.83	227,961	98	50	273,553
3.33	470,685	100	100	141,206
0.87	157,468	33	51	181,088
2.5	206,926	100	100	82,770
1.0	138,050	67	76	138,050
3.0	147,404	100	100	49,135
0.88	137,387	94	54	155,705

Information is also available on results of wells arranged under two different spacings in the Meyer zone of the Santa Fe Springs field of California. The sands here are unusually thick, and abnormally high per acre recoveries have been secured. Development has been characterized by highly competitive conditions and the data are of special interest in that few studies of the sort have been made in other "town-lot" fields. Table X gives the results. It will be noted that while intensive development of the character of that at Santa Fe Springs has been generally condemned as uneconomic, close spacing has effected a much greater recovery than normal spacing from the per acre standpoint. Table X shows, however, that the production figures do not accord even approximately with Cutler's theorem.

A study of recoveries secured by different spacing of wells in the Long Beach field of California by Roberts and Sweeney also shows that close spacing of wells is in every case productive of the greater per acre recovery, though the greatest production per well has invariably been attained by wide spacing. Table XI gives the results of this study.*

Graphical Analysis of a Well-spacing Problem.—With the aid of production data for several different spacings of wells, such as have been presented in the tables reproduced in connection with the foregoing section, supplemented by cost data that can be readily assembled, it is possible for the engineer to approach the problem of estimating the most profitable spacing of wells by a procedure which we might call "graphic analysis." Figure 24 will serve to illustrate the method: A start is made by plotting points showing production per well and ultimate recoveries per acre for different spacings from such data as may be available. The "recovery per well" and "total-ultimate-recovery" curves are then drawn through these points, as illustrated

* UREN, L. C., The Spacing of Oil Wells: Field and Experimental Data, *Nat. Petroleum News,* Mar. 19, 1930, pp. 78–84; Mar. 26, 1930, pp. 61–64.

in Fig. 24. We then compute points on and construct from known drilling costs the "total-development-cost" curve, and, dividing the total acreage development cost by the equivalent estimated recovery figures, we derive the "development cost per barrel" curve. As might be expected, the unit development cost is shown to increase rapidly as the spacing diminishes. We next construct a similar curve showing the unit production cost. Total operating cost diminishes as the number of wells to be pumped decreases, but a larger number of wells means a shorter period of operation and a greater total production, all of which tendencies combined result in a slightly increasing unit production cost as the spacing is increased.

Another element of cost that must be taken into account is the interest cost of deferred production which, of course, increases as the spacing increases, owing to the slower rate of recovery. Summation of the ordinates of these three cost-element

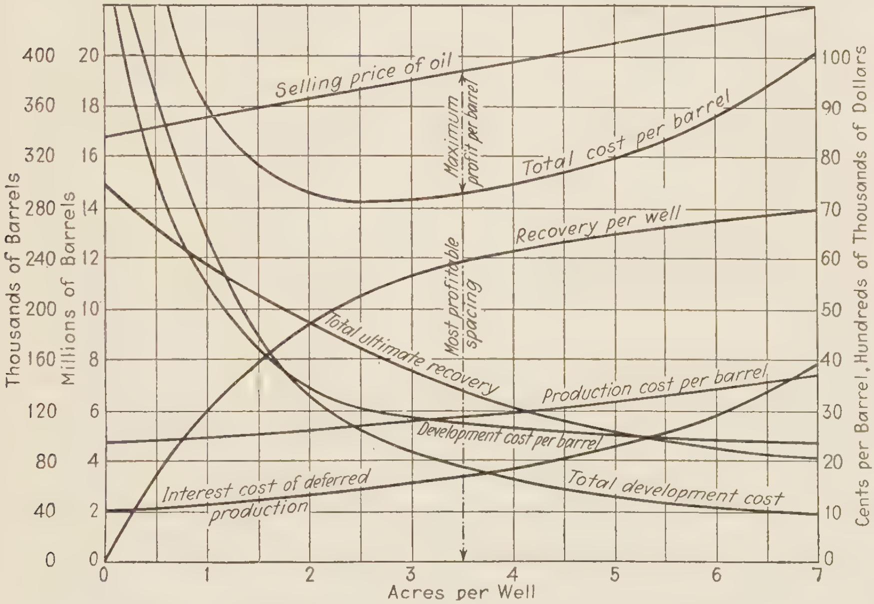


FIG. 24.—Illustrating graphic solution of well-spacing problem.

curves gives points on the "total cost per barrel" curve, which shows a minimum unit production cost, in this case, of 71 cts. at a spacing of 2½ acres per well. This, however, does not indicate the most economic spacing unless the unit selling price of oil is assumed to remain constant. In Fig. 24 the selling price is assumed to gradually increase in future years, and, owing to the slower rate of recovery as spacing is increased, a higher average price is realized. The maximum distance apart of the "selling-price" curve and the "total-cost" curve is attained at a spacing of 3½ acres per well. The cost per barrel for this spacing is shown to be 73 cts. per barrel and the profit, the difference between this and 97 cts., or 24 cts. per barrel. The ultimate recovery per well for this spacing will be about 240,000 bbl., and the total ultimate recovery (for a tract of 120 acres in this case) will be about 6,750,000 bbl. To realize this, we shall have to expend $1,850,000 in development work, or 27 cts. per barrel of oil recovered. The production cost per barrel will be 29 cts. per barrel and the interest cost of deferred production is estimated at 17 cts. per barrel.

With sufficient data, it is possible to analyze any well-spacing problem along these lines and display the results in convenient form for inspection and analysis. In secur-

ing additional points on the recovery curves, in the event that sufficient data are not available to construct them, recourse may be had to such formulas as those proposed by Dr. W. P. Haseman[6] and Mr. R. W. Phelps.[9] It will be noted, however, that this method of analysis is useful only in studying the results of production on properties already developed or in course of development and that sufficient data will generally be available only after the operator is already committed to a certain development program, which may or may not be the most economic one. In other words, such a method is useful only in retrospective analyses and does not provide a dependable means of predicting proper spacing for an undeveloped property.

Laboratory Research on the Well-spacing Problem.—Some aspects of well spacing lend themselves well to laboratory study, and, while but little work of this character has been done as yet, it is possible that laboratory research may eventually contribute in an important way to the ultimate solution of the well-spacing problem. The author and his coworkers in the University of California petroleum-engineering laboratories have for some years been conducting recovery experiments in sand-filled pressure-drainage apparatus, which would appear to afford a new method of approach. Though contrary to all the field evidence, one interesting group of experiments has indicated that very close spacing of wells may result in smaller gross ultimate production of oil from a tract of land than will be produced by a fewer number of wells. A possible explanation of this is found in the more rapid depletion of field pressure and the greater wastage of gas energy that attends operation of the larger number of wells. An experimental study of the pressure gradient in an oil reservoir sand maintained under conditions approximating those in the vicinity of a high-pressure well has been productive of results which permit of predicting the drainage radius of such a well under a given set of conditions with fair accuracy. Description of the apparatus used in these experiments and more detailed narration of the results are reserved for Vol. II, of this treatise.

Looking toward the development of a practical means of determining the most profitable spacing under a given set of field conditions, it would appear to be possible through experimental research to establish a unit of sand permeability, comparison with which, for a given field pressure and thickness of sand, would at once determine the quantity of oil that could be extracted by a specified method of well operation under any spacing interval that might be adopted. It then only remains to balance cost against revenue to determine the spacing that would be most profitable. It should be possible on this basis, with sufficient experimental and field data as a guide, to estimate from laboratory tests on cores of the oil sand and closed-pressure measurements taken in a single well (before it has been allowed to produce) the proper spacing for wells on the acreage immediately surrounding. As these are drilled, they, in turn, furnish similar criteria for spacing of wells to be drilled later on adjacent territory. The economic spacing is not properly constant but may conceivably vary widely, even within areas of limited size.

Economic Aspects of Well Spacing.—Losses due to improper well spacing must aggregate truly prodigious amounts from the national standpoint. There are undoubtedly many fields where highly competitive conditions have led to the drilling of more wells than the productive area can properly support. Many wells in the crowded town-lot sections of the Santa Fe Springs and Long Beach fields of California, for example, are so closely spaced that they will never pay out. A high per acre yield will result from intensive development, but the cost of drilling and operating so many wells will be more than the value of the oil produced. Doubtless, in many closely drilled areas, there will be some profit, though it will be less than it might have been with wider spacing. On the other hand, many of the more conservatively developed fields have been drilled with wells that are too widely spaced for maximum profit. Great areas in Mid-Continent and western American fields have been drilled with an

allowance of 10 acres per well, and yet computations indicate that in some cases profits could have been doubled or tripled by adopting closer spacing. Present information does not admit of anything more than speculation on what the aggregate loss has been from the national standpoint, but rough computations based on data from a few fields on which results have been assembled, suggest that it is probably greater than the profit that has been realized on all of the oil thus far produced.

Circumstances over which the individual producer has little or no control have contributed in an important way to the financial loss resulting from improper well spacing. The competitive principle in oil-field development is a fundamental difficulty, the influence of which can never be entirely overcome until the industry finds a means of effecting unit exploitation of oil pools. The small size of many competitive tracts, with resulting obligations to offset neighboring activities and protect boundaries, often compel the producer to adopt a spacing program not in accord with his better judgment. Lack of adequate financial resources during the early stages of development, in many cases, prevents exploitation on the most profitable scale. An oversupplied market often compels a less intensive rate of development than economic considerations would otherwise justify. The program of proration and restriction of development activity that has been followed during recent years, while essential from the market standpoint, nevertheless has dictated a development program that in many fields probably means diminished ultimate recovery and smaller gross income than could have been realized if a reasonable price structure could have been maintained without restriction of output. This situation can perhaps best be remedied by the expedient of shutting in all wells and deferring all development activity in flush fields until market conditions favorable for exploitation on the most profitable scale are realized.

Well spacing as a community problem is a matter in which some central agency, such as the American Petroleum Institute, should become interested in a substantial way, with the purpose of standardizing spacing practice in all fields on a scientific and economic basis. Losses due to uneconomic spacing of wells have been enormous and will continue until a concerted effort is made to systematize well spacing in new fields along scientific and economic lines and not with respect to property lines. Without doubt, economic well spacing is the most important unsolved technical problem before the present-day oil-producing industry.

Estimating Economic Life of Oil Properties

The economic life of an oil-producing property is that period of time within which, if all oil that may be profitably produced is marketed, a maximum profit will be realized.[14] The estimation of this economic life period is a problem that confronts every oil producer in planning the development program for his property, particularly in determining the maximum rate of productivity that he should strive to attain. Given a certain tract of undeveloped land known to be oil bearing, should all of the wells that the land will support be drilled at once, or would a less intensive program be more profitable? Will it be more profitable to produce as much oil as we can get early in the productive life of the property, or would it be preferable to conserve the bulk of the oil in the ground until some future period? Obviously, the productive life of the property will have an important bearing on estimates of production costs and on the present value of future income to be derived from oil sales.

Estimation of the economic life period of an oil-producing property is a problem that involves the same physical and economic factors that have already been discussed in connection with the well-spacing problem. Indeed, the estimation of economic life is but a different form of the same problem and is subject to the same limitations that were found to apply in connection with the well-spacing problem. The rate of production decline, the cost of production and the selling price of petroleum are mutually interrelated factors limiting the period of economic operation of an oil-producing property. The lower limit of profitable operation is reached when the cost of producing a barrel of oil is equal to its selling price. As the rate of oil production declines, the cost per barrel rapidly increases, but, as the critical period is reached when lifting costs are almost as great as selling price, the economic life may be greatly prolonged by a moderate increase in selling price or decrease in operating expense

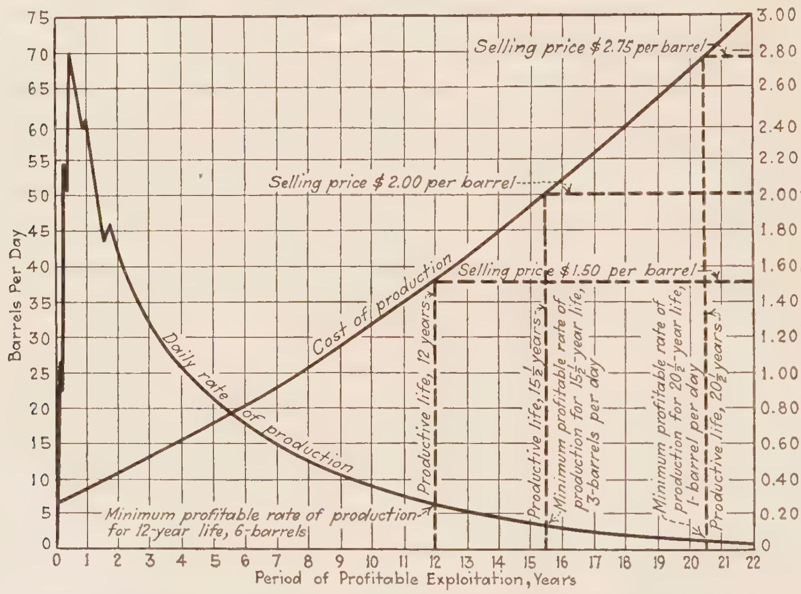


FIG. 25.—Illustrating influence of selling price of oil on the economic life of an oil-producing property.

Figure 25 illustrates a typical case. At a selling price of $1.50 per barrel, the limit of economic well operation is reached during the twelfth year of operation, when the production is 6 bbl. per well per day; but if the selling price is increased 50 cts. per barrel, or the cost of production is reduced by a like amount, the profitable life is prolonged by 3½ years, and, if the price is increased to $2.75 per barrel, the property may be profitably operated for 20½ years.

The graphic method of analysis that was found to be useful in analyzing the factors entering into the well-spacing problem may again be resorted to in making approximate estimates of economic life of oil properties. A typical example will serve to demonstrate the method of graphic analysis as applied to the economic life problem. Let it be assumed that the property in question consists of a section of land—a mile square—and that the entire tract is known to be commercially productive by reason of wells that have been drilled about its boundaries. Decline curves from early wells drilled on neighboring tracts and the known costs of development and operation elsewhere in the field, or in similar fields, permit of approximately estimating the oil recoveries possible from year to year and the production costs for different assumed

development programs. From such data it is estimated that if wells are spaced so that there will be 2 acres of land per well, the property will be exhausted in 4 years; if 4 acres are allowed per well, the recoverable oil will be secured in 9 years; if 6 acres, 14 years; 8 acres, 21 years; 9 acres, 26 years. A study of cost data for these different rates of recovery gives the data of Table XII. Estimates of the future selling price of petroleum, based on market trend, indicate the average selling prices per unit of product, which are given in the last column of the table. The second column in the table gives the acreage per well that must be allowed to exhaust the property in the number of years indicated by the figures opposite in column 1. The estimated cost of drilling the necessary number of wells and providing incidental surface equipment for the different periods of time assumed in column 1 is indicated in column 3, and column 4 shows the estimated cost of pumping wells to economic exhaustion during these periods. Column 6 gives estimates of average selling price of the product for each of the several assumed periods of exploitation. The difference between these figures representing average selling price and the sum of the figures opposite in columns 3 and 4 gives the average apparent profit per barrel of oil. These figures are discounted by a factor representing the interest loss to determine the "interest cost of deferred production" given in column 5. In making this computation, an interest rate of 10 per cent is adopted and it is assumed that the average period of deferred payment is about one-third of the total number of years necessary for exhaustion given in column 1.

TABLE XII.—DATA COMPILED FOR USE IN GRAPHIC SOLUTION OF TYPICAL ECONOMIC LIFE PROBLEM

(1) Number of years necessary to exhaust property	(2) Acres per well	(3) Capital cost of development and equipment per barrel	(4) Operating cost per barrel	(5) Interest cost of deferred production per barrel	(6) Average selling price of oil per barrel
4	2	$1.50	$0.28	$0.03	$1.72
9	4	0.90	0.52	0.15	1.86
14	6	0.65	0.74	0.30	2.02
21	8	0.52	0.98	0.59	2.26
26	9	0.48	1.09	0.67	2.37

The assumed and computed values given in Table XII are next plotted on coordinate paper as illustrated in Fig. 26. Five points on each curve are sufficient to determine its entire course with fair accuracy. Graphic addition of the ordinates of "capital-cost," "operating-cost" and "interest-cost" curves determines points on the "total-cost-of-production" curve. The length of ordinate between this latter curve and the "selling-price-of-oil" curve shows the probable average profit per barrel of oil for any assumed time of exhaustion for the property. It is to be noted that the maximum profit per barrel is realized when the period of exploitation is 11½ years, which is, therefore, the economic life of the property. Intersection of the 11½-year ordinate with the "acres per well" curve indicates the spacing of wells necessary to accomplish drainage within this time.

This method of estimating the economic life of an oil property assumes that the same quantity of oil is ultimately produced irrespective of the spacing of wells assumed. The ultimate recovery, however, is secured in a briefer interval of time by closer spacing. This assumption is true only so long as the acreage per well assumed does not result in the wells being spaced beyond their natural radius of

drainage, thus leaving undrained spaces between wells. This maximum radius of drainage is dependent upon the physical properties of the oil and the lithological and structural properties of the reservoir rock, and its evaluation constitutes a separate problem which must be solved before the economic life period can be estimated. Discussion of the drainage radius of wells is reserved for Vol. II of this work.

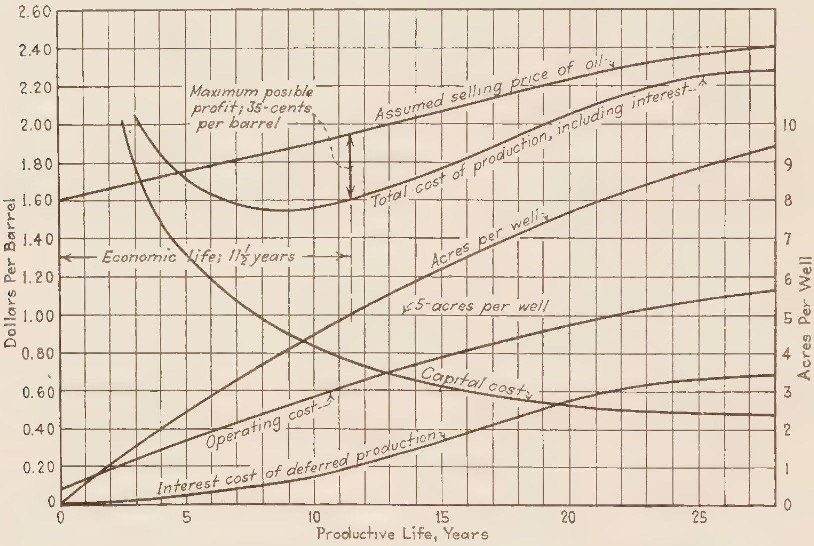


Fig. 26.—Illustrating graphic solution of the economic life problem.

Further consideration of the graphs of Fig. 26, particularly of the region between the curves representing the selling price of oil and the total cost of production, shows that serious losses are incurred by unduly shortening the productive life. For example, if a 7-year life is assumed, 35 per cent of the potential profit is sacrificed; and if the period of recovery is reduced to 5 years, the profit is only one-tenth what it would be if the property were exploited for the economic life period. An unduly prolonged productive life also reduces the potential profits, though losses do not seem to be so great in this direction. The important influence of increasing oil prices on the period of economic life is particularly worthy of note. If conditions were such that a declining or stationary price structure could be anticipated over the greater part of the period of productivity, a shorter economic life period would result.

Development of Surface Plant and Equipment

The drilling of wells constitutes only one phase of the general problem of oil-field development. In addition, the operator must give attention to the building of roads to facilitate transportation of materials and equipment, and power and water development and distribution must also be considered. The provision of a gathering and storage system is essential, and the erection of buildings to house shops, reserve supplies, power plant, office staff and equipment, sleeping and dining facilities for the employees, living accommodations for their families and other camp necessities will be important considerations in the early development period.

Transportation of supplies and equipment will necessarily receive early consideration, for timber, rig irons and parts, drilling equipment and casing must be hauled to the sites selected for the wells. Ordinarily, motor trucks will be used in transporting supplies and equipment, so the roads constructed must be capable of withstanding heavy loads and the grades should not be excessive. Routes should be selected which will give convenient access to all parts of the property.

Unless the property is near a town where ordinary living accommodations are available for employees, camp facilities must be provided in advance of other development work. Such facilities may not at once be developed to the same degree as may be necessary or desirable during later years, but the initial effort in this direction must be adequate to provide the necessary camp conveniences. Machine and forge shops adequately equipped to care for such repair work and tool dressing as will be necessary must be provided in advance of development work; and a warehouse and office building to house the clerical and technical staffs must be built. These facilities may be of rough temporary construction, with the expectation of replacing or improving them later if results of development warrant it, but if it is certain that the property will be productive over a considerable period of years, it will be more economical to build at the outset for the estimated productive life of the property.

The provision of power will be an important matter. This requires, first of all, selection of the form of power, which may be either steam, electric or gas power. If steam power is determined upon, it will be important to develop a source of water suitable for boiler purposes. This may necessitate the drilling of a water well or the construction of a dam, or it may be necessary to buy water from outside sources. Distribution of water over the property will require a piping system adequate not only for boiler purposes but to provide water for drilling needs as well. The erection of boiler plants with all incidental and related equipment at various points about the property, or of a larger central plant, will require careful designing if reasonable efficiency is to be secured. Distribution of steam from power plants to the points of use will require a system of steam mains. Electric power necessitates the installation of poles, wiring and transformers in addition to the steam plant, unless power is purchased from outside sources.

As soon as the first well is completed and placed on production, it will be necessary to provide oil storage sumps, reservoirs or tanks and gathering facilities for both oil and gas. This part of the surface equipment will ordinarily be developed gradually to keep pace with the productivity of the wells as completed, but its layout and design should be carefully planned in advance with reference to the shape and size of the property and the topography. Gas traps of suitable capacity and design

must be provided to separate occluded gas from the oil. Dehydrating equipment, often a very essential part of the surface plant in the declining years of the property, is not ordinarily necessary during the early development period.

In addition to the foregoing essential features of the surface plant, many other details must receive consideration: an electric lighting system is desirable; telephonic communication with various parts of the property will be a great convenience; fire protection is important. An absorption or compression plant to strip gasoline from natural gas, or a small topping plant is often an incidental part of the oil-lease equipment.

The equipment of the property belongs distinctly to the development period. While the surface plant must be developed more or less gradually, the property cannot be expected to operate at maximum efficiency until the surface equipment is complete and every element of it is properly coordinated. Both the cost of the plant and the cost of development represent capital outlay that will be productive over the greater part of the life of the property, and as such they are of equal significance in planning for its development.

INFLUENCE OF PRODUCTION CONTROL ON OIL-FIELD DEVELOPMENT

Competitive methods of exploitation of oil fields have at times been responsible for production of petroleum in excess of market needs. Under competitive stimulus the activity of each producer is dominated by the necessity of taking possession of the oil within reach of his wells at the earliest possible moment. Market needs are subordinated to competitive necessity, and once brought to the surface the oil must be marketed, for storage is expensive and evaporation losses are high. In this way, oil is produced in defiance of fundamental laws of economics, production only remotely responding to demand and price. The result during recent years has been persistent overproduction and dumping of surplus oil on an oversupplied market at prices far below the product's intrinsic worth. Overproduction results in price depression, occasionally to levels below the cost of production, and leads to general demoralization of the industry. Cheap oil leads to wasteful use and use for inferior purposes. A low-priced product cannot be so efficiently produced as a high-priced commodity. Much of the inefficiency of the present-day oil industry is chargeable to the low price which the product commands. Much oil is today left in the ground because more efficient methods of recovery are unprofitable. Operators are necessarily forced to skim the cheaply produced "flush" oil with the aid of the natural energy with which it has been endowed. Highly competitive production methods make less efficient use of the natural gas energy stored in the oil than would be possible under more orderly and systematic methods of well control.

So seriously has overproduction influenced the welfare of the oil industry during recent years that producers have resorted to cooperative methods designed to secure some measure of production control. Though essential from the standpoint of general welfare and preservation of a remunerative market, cooperative production control, of necessity, restricts the oil producer's freedom of action in exploitation of his property. His development program may be dictated by the general industrial situation to such a degree that some of the principles set forth in the preceding sections of this chapter must be modified or even entirely disregarded.

The theory of jurisprudence which regards oil and gas as fugitive substances, belonging to whoever may be in a position to reduce them to possession, has been seriously questioned within recent years and seems to be gradually yielding to a viewpoint which regards the oil and gas present in a geologic structure as community property. This view recognizes the right of the landowner to produce only so much of the oil and gas as may have been stored by nature within the boundaries of his property. In primary exploitation, his proprietary interest is further limited to such oil as he may be able to produce with his share of the natural energy associated with the oil and gas. The oil and gas pool in place of the individual tract of land is thus recognized as the production unit. While this advanced theory of ownership of oil and gas resources has not as yet been written into our governing laws, it has been inferentially recognized by some of the oil- and gas-producing states in their exercise of the police power in enforcement of regulatory laws which have been upheld by the courts. This theory of oil and gas ownership has also been advanced by such authoritative bodies as the U. S. Federal Oil Conservation Board, the American Petroleum Institute and the American Bar Association.

Proration Practices in the United States

This recognition of the rights of the community as superior to the rights of the individual producer has provided the basis for a system of production control that has found wide application within the oil-producing industry during recent years. This has taken the form of proration of the right to produce oil and gas among the various producers in the more active flush fields in accordance with their ability to produce. The market requirements for a given period are first estimated. The potential production of each operator and gross potential production are then determined. Dividing the volume necessary to supply market needs by the gross potential production, we arrive at a factor or percentage which is applied to each individual operator's potential production to determine the amount that he will be permitted to produce during the period.[19]

Proration authority has been in large part vested in regional and district "umpires," who have proceeded in accordance with rules adopted by associations of producers. Their authority has been based in most cases, on nothing more than a gentleman's agreement among the producers or voluntary subordination of the individual to the decisions of the association of which he is a member. More recently proration machinery so set up by voluntary associations of producers has been taken over by state commissions, the orders of which have been given the sanctity of law. Semiofficial review of the periodic estimates of market requirements upon which proration allowances have been based has been given by state and Federal authorities. Committees of the American Petroleum Institute and the Federal authorities have undertaken, in an advisory way, to apportion the necessary national production among the several producing states, and state proration authorities have, in turn, adopted the suggestions of the national agencies as the basis for their own programs. This procedure probably comes as near to control of production by mutual agreement among producers as is permissible under existing anti-trust laws.

It has been generally recognized that any authority which government might have to regulate production of petroleum, except in time of national emergency, is vested in the individual state governments. Accordingly, proration rules have varied somewhat in different jurisdictions in accordance with the views of local authorities. In some districts, for example, allowable rates of production for individual operators have been based on potential productions of existing wells on their properties. Occasionally, test periods are designated, within which wells are allowed to produce at maximum rate to determine the potentials upon which restricted yields are based. Fields in flush production are often restricted by a larger percentage of their potential rate than is applied in fixing the allowable production of the older fields. In some districts allowable production rates are computed on the basis of proven oil land owned by each operator, a flat rate per acre being allotted. In some instances, permissible production rates are a function of both acreage and potential well productions, being based on arbitrary formulas which give weight to both factors. It has also been suggested that proration allowances might be based upon the gas energy present in the formation, as exhibited by pressure conditions and gas-volume measurements at the various wells.

Unit Exploitation of Oil Pools

Many of the disadvantages of competitive exploitation may be avoided and production control greatly facilitated by the adoption of a plan of operation in which all land owners in each field agree to pool their interests in a single operating organization or to conduct their operations

in accordance with a general plan upon which the majority agree. The individual pool or field thereby becomes the production unit, as is desirable from the standpoint of recovery efficiency; and yet, associations of operators in different pools may still compete with each other for their share of the market demand.[29]

Advantages of Unit Exploitation of Oil Fields.—Very definite advantages and economies accrue to the oil producers in any field through unitization of development and producing operations in comparison with what is possible by competitive exploitation. Unit operation permits of more systematic and orderly development, leading directly to more efficient recovery of the available oil and gas. Through group control of oil-producing properties, a superior gas-pressure control, more uniform well spacing and better coordination of drilling programs are possible. More efficient production methods and concerted effort to exclude water will inevitably lead to increase in the percentage recovery. This represents direct conservation of natural resources and should appeal not only to the oil producer but also to the consuming public and to the government, which is interested in securing an adequate supply of petroleum as a guarantee of national security in time of war. Probably more can be accomplished through conservation of this character than by any other means. It may be possible to double or even triple our reserves through the use of more efficient methods of extraction which group-exploitation methods would make possible. In addition to actual physical wastage of oil, which the competitive system of production entails, the economic losses resulting from unnecessary duplication of plant and personnel, overdrilling and generally higher production costs incidental to small scale operations also have an important bearing on conservation of oil and gas resources.[21]

The Trend toward the Unit Plan.—Nearly all students of petroleum-industry economics now agree on the desirability of unitization of the oil-producing industry in the United States, but as yet there is no general agreement on the means by which it is to be accomplished. Many plans have been proposed, most of which present certain difficulties, some of a legal character, some economic. Some present an attractive picture from the academic point of view but are unsuccessful in application because they fail to recognize the vagaries and prejudices of human nature. Unitization by any plan involves a surrendering of certain rights which, under the competitive system, the independent operator now enjoys. Many oil producers have lacked sufficient confidence in their competitors willingly to surrender these rights and view with suspicion a program which would admittedly involve very radical changes in existing relationships. They have failed to recognize the great advantages that would accrue and compensate for such sacrifices; nevertheless, a gradual change in sentiment within the industry has been

apparent. A few years ago, there were few who were willing to accept the "unit plan." More recently, most of the recognized leaders of the industry have expressed themselves as favorable toward it and it has received the endorsement of the Federal Oil Conservation Board, the American Petroleum Institute and the Mid-Continent Oil & Gas Association.[27] A committee of the American Bar Association has recommended it as the only plan offering permanent relief from the irrational and uneconomic situation with which the industry has had to contend.

Unitization of the oil-producing industry is at once a remedy for the vexing problem of overproduction, a means of conserving and efficiently utilizing what remains of an invaluable and irreplaceable natural resource, and of reducing the unit-production cost of American petroleum so that it may compete to better advantage in world markets with cheap flush oil produced abroad. It will assure the producer of a more stable price structure and greater ultimate profit than is possible under the competitive system. These are statements that can be proved to the satisfaction of any reasonable business man, and in the main they are accepted by the majority of oil producers; it but remains to find the most acceptable way of bringing about the desired change. Some believe that the producers in various fields can be induced to voluntarily pool their properties or at least to enter into agreements to conduct their operations in accordance with a common plan. Others who have observed the difficulty with which such agreements are secured, believe that coercive measures are necessary and are recommending legislation that would make it possible for a majority of the operators in each productive field to determine upon a program by which all must abide. In case of opposition from minority interests, the police power of the state would be invoked to make the majority program effective.

Possible Methods of Accomplishing Unitization of Oil Pools under Competitive Conditions.—It is interesting to compare some of the plans that have been proposed for bringing about unitization of the oil-producing industry. They range from simple cooperative agreements among neighboring producers to elaborate systems of legal enforcement in which the Federal or state governments are to be given power to compel and enforce operation of fields as units. We may conveniently classify the various proposals into two groups, (1) those which assume voluntary agreements as the basis for unitization and (2) those assuming some degree of Federal or state enforcement.

Unitization by Voluntary Cooperation of Producers.[25]—Considering first the voluntary cooperative plans, varying degrees of unitization are possible, ranging all the way from simple offset and spacing agreements to complete merging of properties and interests in a single operating organization. If the producer recognizes the advantages and accepts the principle of unitization, he should be prepared to go all the way, for only by complete unitization are the maximum benefits of the plan realized. Often, however, this is difficult of attainment owing to conflicting interests and lack of agreement on comparative values of different tracts. In most cases where efforts toward voluntary cooperative unitization have been made, an unwilling or unreasonable minority has defeated its consummation. When this method must be depended

upon, a compromise plan falling somewhat short of complete unitization must generally be accepted.

Cooperative Agreements with Divided Interests.—Usually it will be easier to negotiate a cooperative agreement among a small group of producers than among a larger group. There have been many instances in which a number of operators have agreed to exploit their properties according to an agreed plan to their mutual advantage. One of the best examples of this form of unitization is found in the Dominguez field of California, where two large companies owning most of the productive area have developed the field in accordance with a common spacing and penetration program, have agreed to maintain uniform pressure conditions in the productive wells and are cooperatively injecting surplus gas into wells on the crest of the structure in an effort to maintain field pressure. As a result of this cooperative work, a materially greater recovery is indicated than if the usual competitive methods were followed.

Complete Unitization with Undivided Interests.—Generally it will be easier to achieve complete unitization in advance of development activity than at a later date when irregularity in the extent of development and real or fancied differences in value of the various tracts will complicate the problem. In a prospective field yet to be tested by the drill, land titles will generally be subdivided among several or perhaps many different owners. Instead of owners retaining title to their individual tracts they may agree to pool their interests, each accepting in lieu of his specific title an undivided interest in the entire acreage, proportional to the ratio of his acreage to the total acreage. Each owner then contributes in the same proportion to a fund for drilling one or more test wells and such other development and exploration expense as may be necessary.

One difficulty experienced in carrying out this plan is that of determining how much acreage should be included in the unit. Where this consideration is of importance, it may be provided that each tract (say each 40 acres) must be tested and proven by the drilling of a productive well before being admitted to the unit; or, if admitted in the preliminary organization, that the owners may receive no revenue until their tracts are proved to be oil bearing.

Control of the enterprise may be placed in a new trustee company formed for the purpose, in the stock of which the several owners share in proportion to their acreage; or, by agreement, one of the group may be authorized to conduct the development and exploitation of the entire property under the scrutiny of an executive committee representative of all of the owners. The royalty owners should be included in the organization if the greatest advantages of the plan are to be realized, but it is possible to proceed without their cooperation by giving due attention to the securing of equitable drainage of the different tracts. The necessity for doing this, however, defeats in part, the fundamental advantages of the unit plan. The right to develop and operate their individual tracts may be reserved to the members under general unitization rules laid down by the executive committee, but this is less desirable than the alternative plan of entrusting exploitation of all properties to a single organization, for only by this means may maximum efficiency and minimum unit production cost be realized. Unitization with undivided interests has been approved by the Mid-Continent Oil & Gas Association, and rules for the guidance of members in entering into unitization agreements have been formulated and adopted.[27]

An interesting example of successful unitization through the pooling of prospective acreage and retention of undivided interests is found in action taken by operators in the Van field, Van Zandt County, Tex. Here 5,800 acres of prospective productive territory, owned by six different companies, have been pooled and an operating agreement worked out whereby one of the six is developing and operating the tract as a unit under the general supervision of an operating committee composed of one representative of each of the member companies. The cost of development and exploita-

tion is prorated among the member companies on an acreage basis, and profits are distributed on the same basis for the first 2½ years. Then an independent engineering appraisal of the properties is to be made and a new operating agreement drawn up in which the values instead of the acreage of the different tracts will be the basis for assessment of expenses and distribution of profits. Provision is also made for revaluation of the properties after another 2½ years have elapsed, with readjustment of values set up in the first appraisal. An unusually thorough geological and geophysical survey of the field made in advance of any development work provided the basis for determination of prospective acreage to be included in the unit.

Another plan appropriate for use in unproven areas, is the "community lease." Here a promoter seeks to secure the advantages of unit exploitation by inducing all landowners in a prospective area to lease their acreage to a single operator. Allocation of royalties among the lessors is in this case on an acreage basis rather than a production basis. Such a lease was consummated by the Union Oil Company of California in connection with the operations of this company on the Wellington dome in Colorado. In another instance, at Belvedere Gardens, in the Los Angeles basin of southern California four community leases were negotiated by one company in a townsite area from 2,000 separate landowners.

A more difficult situation is presented when it is proposed to unitize properties in a field that has already embarked on its productive career. Here the various tracts are normally found in different stages of development, field pressures depleted in varying degrees, different spacing and development programs have been followed and the physical condition and equipment of the plant and wells will vary widely on different properties. It would be obviously unfair to base the relative interests of the property owners on acreage contributed to the unit without regard to relative values of different tracts, and when we come to fix relative values that would be acceptable to all concerned, we are confronted with a rather difficult problem. Yet, it would seem to be a reasonable procedure for all owners to agree to entrust the appraisal of the properties to a group of disinterested engineers and abide by the result. The appraisal should be based on an estimate of what the properties would be worth under competitive conditions rather than on what they will actually yield under unit operation.

Once appraisals acceptable to all concerned have been prepared, we may proceed with the unitization program along either of several lines. If the owners wish to retain technical ownership of their individual properties, it may be arranged that each tract shall be assigned for a period of years to a trusteeship to be operated in the common interest, all expenses and profits being distributed pro rata among the members in accordance with the initial valuation of the properties. A better plan is that in which the individual operators, both lessees and royalty owners, exchange titles to their holdings for stock in a new company organized as a holding company to take charge of and operate the properties as a unit. Such a plan offers the maximum advantage from the unitization standpoint. If all producers and royalty owners in a producing area will but agree to accept appraisals of their properties by a group of disinterested and competent engineers, there would seem to be no particular difficulty in carrying through a unitization program on the latter basis. If control of production is a matter of importance to individual owners, it might be provided that each owner may claim his percentage of the oil produced in lieu of a monetary profit from its sale. If some of the properties are not sufficiently developed to permit of a satisfactory appraisal of their present-day value, the early adjustments of percentage ownership in the unit may be tentative and subject to revision at a later date when a more precise appraisal is possible. A part of the capital stock and dividends may be held in reserve for a time to permit of making appropriate readjustments in the original tentative appraisals.

One of the outstanding examples of successful unitization of a major field during the early development stage is found in the Kettleman Hills field of California. This field has an estimated productive area of upward of 16,000 acres, nearly half of which is owned in fee by the Standard Oil Company of California, while 15 other companies control nearly all of the remainder. After the productive area of the field had been fairly well delineated by 10 producing wells and the partial completion of more than 20 others, a unitization agreement was effected whereby the group of 15 companies referred to pooled their acreage and vested full control and operation in the Kettleman Hills North Dome Association. A cooperative agreement was also reached between the association and the Standard Oil Company of California whereby a total of 20,260 acres of prospective oil-producing land is to be operated as a unit. A large part of the acreage, other than that owned by the Standard Oil Company of California, is government land, leased under the provisions of the Mineral Land Leasing Law, and officials of the U. S. Department of the Interior took an active part in promoting unitization of the field. Each member company of the association contributes to the expense of development and shares in the profits in proportion to the acreage owned. Provision is made for gradually eliminating such acreage as may be found non-productive. Owners of acreage without the area originally thought to be productive may be admitted to the association on proving the productivity of their land by drilling test wells. The association has not acquired actual ownership of the properties of the member companies but is granted exclusive possession and operating rights thereon. The officers of the association have full authority to determine the development program and methods of well control and operation. Drilling and producing operations on association acreage are in charge of a single field organization.

Perhaps the simplest method of securing unit operation in the case of a group of producing properties is that of a single producer purchasing the property of all of the others. There have, of course, been many instances in which operators have purchased neighboring properties for the purpose of consolidating acreage and securing more economic operating conditions. The Cabin Creek field in West Virginia has been cited by the Federal Oil Conservation Board as an outstanding example of the advantages of single ownership. The entire field was, in this case, acquired by a single company and has been exploited in accordance with scientific and economic principles with special attention given to well spacing and control of field pressures. As a result, controlled production in accordance with market needs has been attained and the rate of decline of the wells has been much more moderate than in other fields of the region.

In a number of instances, efforts at unitization have been made in fields where production had declined to such a point that repressuring or other secondary methods of exploitation were necessary to continue economic operation. Secondary exploitation methods do not adapt themselves well to the competitive system, and operators are generally more willing to enter into a cooperative plan when their properties have reached this stage than in earlier years when they might have considered it more advantageous to retain individual ownership and operate on a competitive basis. A notable example of unit promotion for the purpose of repressuring is found in the Delaware Extension pool, Nowata County, Okla., where properties aggregating 4,140 acres with 629 producing wells were consolidated and placed under a single management. In this case a new company was formed to which previous owners assigned their properties in return for a stock interest in the whole. The basis for distribution of stock was the daily production at the time of consolidation. An arbitrary value per barrel was placed on all production, and relative values were set on natural gasoline production, royalty interests and surface ownership. Surface equipment was purchased at an agreed price. It was unfortunately found to be impossible to pool the

royalty interests in this field, hence the maximum advantages of unitization were not realized. The results have nevertheless been eminently successful in that important increases in the rate of production and economies in assembling and operation of equipment have been achieved. Pressure control on the producing wells, impossible under competitive conditions, played an important rôle in assuring success of the repressuring operations. By unitization this group of properties has been rehabilitated and is in a position to produce at a profit for many years to come.

Compulsory Unitization.—While it is advantageous from every point of view for the individual producer to pool his property with others in a unit operation, practically it is often difficult to secure the consent of all of the operators and royalty owners to do so. If a few tracts, or even a single strategically situated property is withheld from the unit, it may defeat the unitization plan. This situation has so frequently developed that many who have had experience in efforts to promote units are skeptical of the general success of the voluntary cooperative method and are urging legislation as a means of compelling unitization. Varying degrees of compulsion have been suggested by different writers, ranging all the way from national legislation designed to force complete unitization in every field to milder forms in which a state may have authority to enforce cooperation only to the extent that a majority of the operators in each field may elect.

The Federal Oil Conservation Board and a committee representative of the American Bar Association have expressed the opinion that the Federal Government is without authority in legislating on this matter, but both agree that it is within the province of the individual oil-producing states to do so.[24] The American Bar Association Committee concluded that state or national legislation designed to compel operators to merge their properties in an operating unit would be unconstitutional, but that under the police power of the states it would be legal to compel a reluctant minority to enter into a cooperative agreement to operate their properties in accordance with whatever plan of exploitation the majority might elect. The committee went so far as to frame a bill embodying this principle for submission to the several state legislatures. It has also been suggested that an interstate agreement approved by Congress would give federal authority to enforce whatever program the oil-producing states might collectively agree upon.[22]

Restriction of Oil Production by Gas-conservation Laws

Some measure of control of oil production by state authorities is possible through exercise of the right of the state to prevent waste of natural resources. In many flush fields it has been found necessary to produce a certain quantity of gas with each barrel of oil brought to the surface, and the volume of gas so produced has often been in excess of field and market requirements so that much surplus gas has been released to the atmosphere. The state governments have in some cases legislated against wastage of this character, requiring operators to restrict flow of their wells to produce no more gas than may be put to economic use. This has necessarily operated also to restrict oil production; indeed, the gas conservation laws have in some cases been framed and administered primarily as a means of restricting the rate of oil production from flush fields. The California Gas-conservation Law affords a good example of this. The California law declares it to be unlawful to permit waste of natural gas into the atmosphere and gives the State Oil and Gas Supervisor authority to fix reasonable gas-oil ratios in productive areas where gas wastage occurs.[23] He may also approve and enforce operating programs designed to permit gas injection in partially developed oil fields. Strictly enforced, this law would have a powerful tendency to encourage cooperative exploitation and unitization of oil fields.

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CHAPTER V

DRILLING EQUIPMENT AND METHODS; GENERAL FEATURES

CLASSIFICATION OF DRILLING METHODS

The methods used in drilling oil wells may be classified into two groups each utilizing fundamentally different systems of excavation and radically different types of equipment. These are called "churn-drilling methods" and "rotary-drilling methods." We may further classify the various systems of drilling and types of rigs under these two general headings, as follows:

- I. Churn-drilling methods:
  - 1. Cable-drilling systems:
    - *a.* Primitive rigs utilizing "spring poles" actuated by man or animal power.
    - *b.* The American "standard" rig.
    - *c.* Various portable and semiportable rigs.
  - 2. Rod- and pole-drilling systems:
    - *a.* The Canadian pole-tool rig.
    - *b.* The Galician rod-tool rig.
    - *c.* Various types of "free-fall" rigs.
- II. Rotary-drilling methods:
  - 1. Hydraulic rotary systems:
    - *a.* Rigs utilizing mechanical feed control.
    - *b.* Rigs utilizing hydraulic feed control.
    - *c.* The diamond drilling rig.

In addition to this primary classification, we might appropriately establish a third group in which features of both the churn- and rotary-drilling methods are employed. This group may be called

- III. Combination-drilling methods:
  - 1. "Combination" rigs capable of employing either cable or rotary methods as conditions may require.
  - 2. The standard-circulating system of drilling, utilizing churn-drilling tools and a system of removing cuttings commonly employed in connection with the rotary-drilling systems.

Some of the systems of drilling mentioned in the above classification are now almost obsolete in oil-field practice; in fact, only two of them are extensively used at the present time, the hydraulic rotary system and the American standard cable system. The scope of this volume does not permit of a detailed explanation of all of the different systems and types of rigs classified, and we shall therefore devote the available space to a

description of the more modern drilling methods and equipment now extensively employed in oil-field work. The present chapter will be concerned with matters of general interest that relate to all methods of drilling. Chapter VI will be devoted to a more detailed discussion of churn-drilling methods, with particular reference to the American standard cable system, while Chap. VII will describe modern rotary-drilling rigs and methods. The reader is referred to the bibliography given at the close of this chapter for descriptions of the rod-tool and free-fall drilling systems which have been used chiefly in the Russian, Roumanian and Galician fields.[6,10,11]

GENERAL REQUIREMENTS OF DRILLING METHODS

Any successful system of drilling oil wells must provide, first of all, a means of fracturing or abrading the rocky formations which must be penetrated to reach the oil reservoir; and, secondly, it must provide a means of excavating the loosened material from the well as drilling proceeds. In addition, provision must be made for preventing the walls of the well from caving and for sealing off water and gas. Wells should be vertical or nearly so. The well must, of course, be deep enough to reach the oil reservoir, and it should be of adequate cross section to permit of the introduction and operation of a pumping device of sufficient capacity to make operation of the well profitable.

Oil wells vary in diameter within wide limits. Prospect wells, drilled primarily for information rather than for production, may be finished with a diameter as small as 2 or 3 in. Wells in the Russian and Roumanian fields have in earlier years been drilled with initial diameters as great as 36 in. It is usually necessary to decrease the diameter of a well progressively as the depth increases, in order to provide adequate clearance for the drilling tools and to permit of the introduction of metal casings for retaining the walls and excluding water. In American practice, initial diameters commonly range from 10 to 27 in., depending upon the depth to be attained, the number of reductions in diameter necessary and the size with which it is considered desirable to finish the well. This latter factor depends, in turn, upon the productivity of the territory. For American practice, finishing diameters range from 3 to 10 in., most operators preferring a free working diameter of at least 4 or 5 in. The 2-in. plunger pump, which is the smallest size ordinarily used, requires a free working space at least 3 in. in diameter. The 3-in. plunger pump, a commonly used size, requires a free working diameter of about 4½ in. In addition to these working clearances, there must be some space about the pump in which oil can accumulate.

The maximum depth to which it would be practical to drill a well with modern equipment and methods would depend somewhat upon the character of the formations to be penetrated, the size and weight of

the equipment used, the power available and the skill of the driller. Wells have been drilled with churn-drilling cable tools to depths in excess of 8,700 ft. and with rotary tools to more than 10,800 ft. There seems to be no good reason why drilling equipment of either type could not be designed to drill to greater depths if necessary.

The depth to which it is profitable to drill is the determining factor in most drilling operations. This economic limit of depth varies with the quality of the oil, the prevailing selling price, the productivity of the well, the cost of drilling and other factors. Such factors are quite variable. Within recent years, wells drilled to depths ranging from 6,000 to 9,000 ft. have been profitable in some fields where the oil is of high grade and the production rates have been large and well sustained.

HISTORICAL DEVELOPMENT OF THE ART OF DRILLING

The place and time wherein the first wells were drilled are unrecorded in history, but it is known that the Chinese were among the first to make industrial use of wells drilled by mechanical methods. It is said that prior to A.D. 1700 the Chinese had sunk over 10,000 wells to depths of more than 500 m. for the production of brine.[17] The early Chinese well drillers made use of cable-tool, churn-drilling methods and practically all of the equipment used—the rope, casing and derrick—was made of wood, the elastic bamboo being widely employed. The power used was man power. The drilling tools were suspended from the end of a spring pole, the churning movement being given to the tools by the workmen running up a short incline and jumping down, one after another, on a small platform attached to the spring pole. The primitive methods and equipment developed by the Chinese more than two centuries ago may still be observed in drilling operations in interior China, where salt produced by the evaporation of brine pumped from wells is an important article of commerce (see Fig. 27).

The spring-pole method, with minor variations in the manner of applying the power, was also widely used in other parts of the world in drilling wells for various purposes, chiefly for brine. The records of well drilling in the United States begin in 1806, when the first American well was drilled near Charleston, W. Va., for brine. The appliances used in drilling this first American well were very simple. A spring pole 20 ft. long was mounted on a forked stick of wood and fastened to the ground at one end. Attached to the free end of this spring pole, was the drilling cable, to the lower end of which the iron bit, 2½ in. in diameter and quite primitive in construction, was fastened. Stirrups, also attached to the free end of the pole, were used by two or three men in producing the necessary churning motion, their weight pulling the cable down, while the elasticity of the pole served to jerk it back with sufficient force to raise the tools a few inches. The casing consisted of two long strips of

wood, shaped into half tubes and wrapped with twine. The conductor was a straight, well-formed, hollow sycamore gum, 4 in. in internal diameter, sunk to bed rock in a shallow pit. Even in this primitive equipment, used on our first American well, all of the essential features of what we now call the "standard" cable system of drilling were present. We still use the same method of drilling, but our equipment is more elaborate.

The first well drilled for oil in the United States was the Drake well, sunk near Titusville, Pa., in 1859. Many of the shallow wells that were

FIG. 27.—A primitive cable-drilling rig used by present-day Chinese in drilling for brine.

drilled in the same locality following the discovery of oil in the Drake well were drilled with the aid of spring poles by hand methods. As might be expected, the early operators of these laborious and slow hand-drilling rigs soon began to contrive mechanical means for applying power. The steam engine was the best known prime mover in the early days, and naturally the first mechanically driven drilling rigs were operated by steam engines. The engines used were of the simplest type: an ordinary reversible engine, with the piston controlled by a plain slide valve—a type of engine which in spite of its inefficiency is widely used even today for the drilling of oil wells. The engine was used to give a reciprocating

motion to the drilling cable through the instrumentality of a large wheel, called a "band wheel," the metal shaft of which was connected to one end of a walking beam by means of a crank and pittman. The drilling cable attached to the opposite end of the walking beam was thus given a churning motion with each revolution of the band wheel.

The first rigs were light and small, for the wells were shallow and the duty not severe. For hoisting out the tools a simple tripod was used, made of three sticks of timber tied together at the top and supporting a crude wooden or iron pulley. The drilling cable was passed over the pulley and power applied to the free end by a hand-power windlass or a mechanically operated hoisting drum. Such drilling rigs served well enough in the shallow territories which were first exploited for oil but were soon found to be inadequate when deeper drilling became necessary or when more difficult conditions were encountered. Small changes were made here, an improvement there. New parts were added as new duties were imposed, until finally there was evolved the modern cable drilling rig which we call the "American standard rig."

Sixty years of development, during which hundreds of thousands of wells have been drilled by this method, have now fairly well standardized the equipment used. However, there is some variation in the size and weight of the parts of the rig to adapt it to the conditions imposed in different fields. Deeper drilling, characteristic of the western American fields, has also been responsible for the addition of certain new parts, particularly for the handling of heavy strings of casing.

The rotary system of drilling is of comparatively recent origin in comparison with the churn-drilling methods. The first recorded use of rotary methods in drilling for oil was in 1901 in the Spindle Top field, near Beaumont, Tex. The formations overlying the oil zone in this field consist of unconsolidated sands and shales that cave seriously when subjected to the vibrations of churn-drilling tools. Its successful use in this field soon led to the use of rotary equipment in other fields, notably in California, where somewhat similar conditions were encountered. For many years it was thought that the hydraulic rotary system was only applicable in fields where relatively soft formations were to be penetrated, but during more recent years the development of hard-rock bits for use with the rotary equipment has extended its field of usefulness, until at the present time there is scarcely any type of rock ordinarily encountered in penetrating oil-producing formations that cannot be satisfactorily drilled by the rotary method.

Both the cable-tool system and the rotary system of drilling are now extensively used in the American oil fields. Each has its place; each its own set of conditions under which it is more advantageous than the other. Their relative advantages and disadvantages are to be discussed in a later section. Most of the more than 300,000 producing wells in the

United States have been drilled with cable tools, but the greater annual footage during recent years has been drilled by rotary methods.

GENERAL FEATURES OF THE PRINCIPAL DRILLING SYSTEMS

In order to impress upon the mind of the reader the principal features of each of the more commonly used systems of drilling, as a basis for comparison, brief descriptions of them are offered at this point, though detailed discussion of equipment and methods of operation and control is reserved for Chaps. VI and VII.

The American Standard Cable System

The standard cable drilling rig is housed and supported by a structure which has two principal parts: (1) the derrick, a high pyramidal framed structure, erected directly over the site selected for the well; (2) a long narrow and comparatively low structure which houses the engine or motor, the belt, a large band wheel and other mechanism provided for applying and controlling the power. These structures rest on suitable foundations of heavy timber, which together with certain other supports for the wheels and other moving parts are known as the "rig timbers." Substantial flooring is provided under the derrick and within the engine house and belt house, and a platform is built at one side of the belt house on the same level as the derrick and engine house flooring and connecting the two (see Fig. 28).

Motive power is transferred from the engine pulley to a large wooden band wheel by means of a belt. The band wheel is mounted, by means of metal gudgeons, on a steel shaft resting in metal bearings supported on two substantial "jack posts." Overhanging the bearing on one end of the band-wheel shaft, a crank is keyed; this may be connected by means of a metal wrist pin to the lower end of a pittman, the upper end of which is attached by a metal stirrup to the end of a "walking beam." The walking beam is a long substantial timber, supported at its center on a shaft and bearing, which permit it to oscillate as the crank revolves. The end of the beam opposite that to which the pittman is attached overhangs the well, and the drilling cable on which the drilling bit is suspended may be attached to the beam with an adjustable temper screw. By means of this simple mechanism the bit is raised and lowered an amount governed by the "swing" of the walking beam with each revolution of the band wheel. The "stroke" of the beam is adjustable by changing the position of the wrist pin in the crank. Five holes are provided in the crank for this purpose, each at a different distance from the center of rotation of the band-wheel shaft. The movement at the end of the beam ranges from 2½ to 4½ ft., each successive hole in the crank adding 6 in. to the sweep of the beam.

On the side of the band wheel a wooden tug pulley is mounted, which provides a means of operating an endless rope drive (the "bull rope") to a large pair of wheels called "bull wheels." These wheels are mounted on opposite ends of a wooden or metal shaft on which the drilling cable is

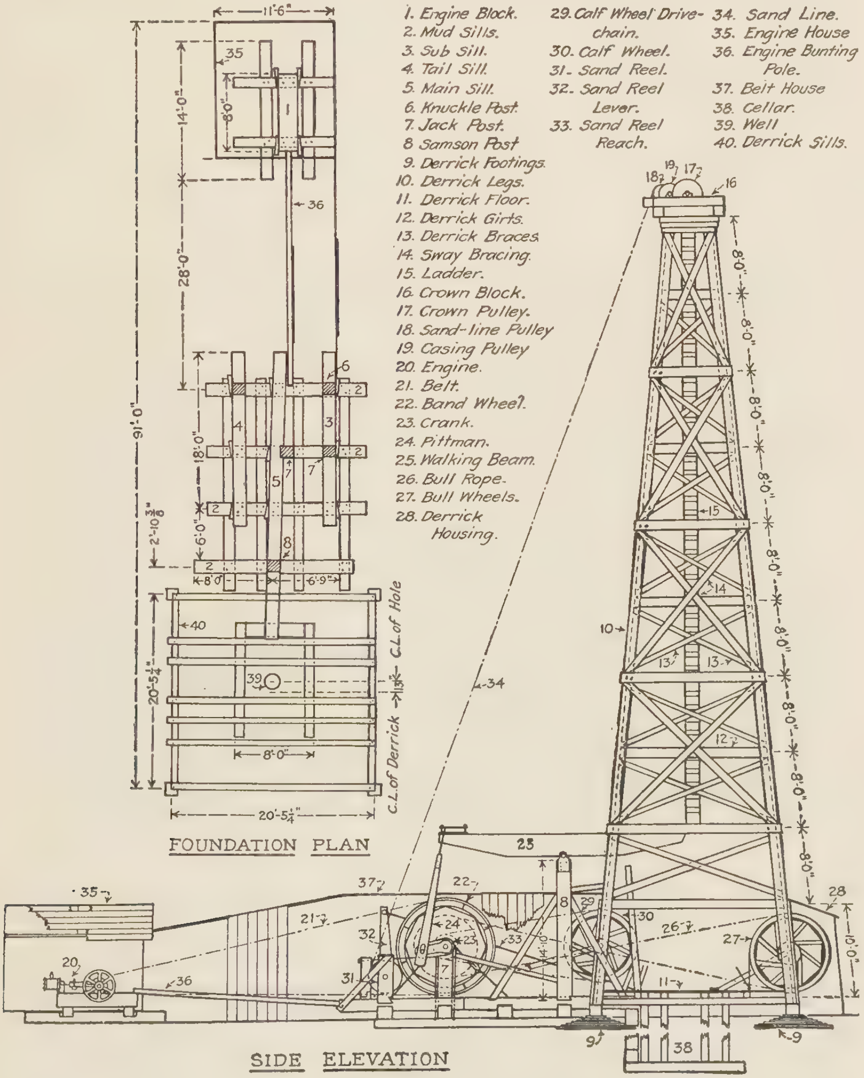


Fig. 28.—Plan and elevation of an 82-ft. standard cable rig.

wound, the free end of the drilling cable passing up through the derrick to a metal sheave on the derrick "crown" and thence vertically downward to the drilling tools in the well. The bull wheels are used for applying the power in hoisting the drilling tools out of the well A band

brake bearing on the face of one of the two bull wheels serves to control the descent of the tools when they are being lowered into the well and to hold them suspended when necessary.

On the opposite end of the band-wheel shaft from that on which the crank is attached, there is mounted a sprocket wheel controlled by a clutch. An endless chain from this sprocket drives another large wheel called the "calf wheel," on the shaft of which the "calf line" is wound. This is a substantial cable, usually of steel, which passes up through the derrick to the crown and is threaded back and forth between four stationary sheaves ("crown block") and three traveling sheaves mounted in a massive frame to which the "dead line" or end of the cable is also fastened. This "hoisting block," as it is called, is used in lowering, lifting

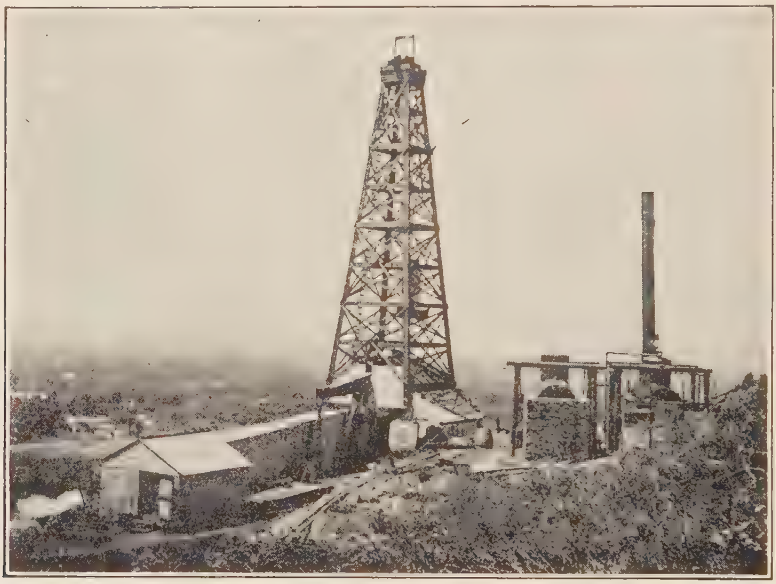


FIG. 29.—An 82-ft. standard cable rig, California type.

and supporting the heavy strings of casing suspended in the well. A large hook and special pipe clamps, called "casing elevators," provide a means of suspending the casing from the hoisting block. A band brake on the rim of the calf wheel serves to control the descent of the casing, or to hold it suspended when the calf-wheel clutch is disengaged.

The "bailer," by means of which the material loosened by the drill is removed from the well, is suspended on a light steel cable or "sand line," which passes over a sheave at the crown of the derrick and thence downward, outside of the derrick, to the "sand reel," a small metal drum mounted on a horizontal steel shaft. The sand reel and its shaft and bearings are mounted on a movable cradle which permits of a friction pulley keyed to the same shaft being brought to bear against the face of

the band wheel, thus revolving the sand reel, winding up the sand line and raising the bailer. The bailer is lowered by gravity, a post brake on the sand-reel friction pulley serving to control the speed.

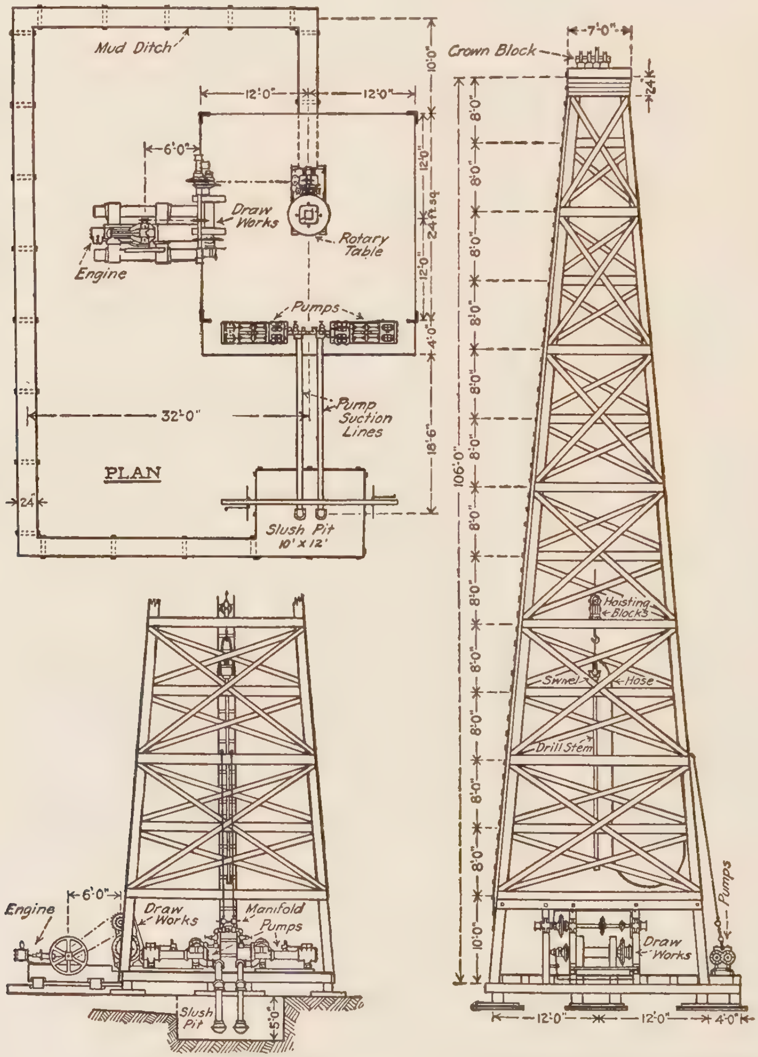
It will be observed that the mechanism described in the foregoing paragraphs has four chief functions: (1) to churn the drilling tools up and down in the well, thus accomplishing abrasion of the material in the bottom; (2) to lower the drilling tools into the well and hoist them out by unwinding or winding the drilling cable on the bull-wheel shaft; (3) to raise, lower and support the heavy metal casing with the aid of the calf line, or casing line, and calf wheel; and (4) to hoist and lower the bailer, used in excavating the material loosened by the drill. In addition to the main features of the rig outlined above, there must be the necessary brakes and levers for controlling the engine and the various wheels and a great variety of tools and implements useful in conducting the work. These will be considered in greater detail in Chap. VI.

General Features of the Rotary System

In the rotary system of drilling (see Fig. 30), the rock mass through which the well is drilled is abraded and chipped away by the downward pressure and cutting and grinding action of a revolving steel bit which may assume various forms. The cutting bit is revolved by a substantial steel pipe or "drill stem," extending from the top of the drilling tool, to which it is screwed, to a point some distance above the derrick floor. At the level of the derrick floor the drill stem passes through a gripping device in a power-driven rotary table mounted over the mouth of the well. The form of the gripping device is such that while the table has a positive grip on the drill stem, the latter is free to move vertically through the table even while it rotates.

To the top of the column of pipe comprising the drill stem a massive swivel is attached, which provides a means of suspending the stem in the well, allowing it to rotate with the table, while the upper part of the swivel, the hoisting block and supporting cables remain stationary. The drill stem and swivel are hollow so that water or mud can be pumped down through the stem to the drilling bit and out into the well through holes, one on either side of the bit. This fluid sweeps under the bit, picks up the rocky material loosened thereby and carries it to the surface through the annular space between the drill stem and the walls of the well. This circulation of fluid through the well is maintained by the pressure of either of two powerful pumps connecting through a flexible connection to the swivel on top of the drill stem. Fluid from the well overflows into a mud ditch or wooden trough through which it moves sluggishly, allowing the coarse cuttings from the well to settle. The fluid thus freed of the coarse gritty material, and containing only fine-grained clay in suspension, flows into the mud sump, from which it is

picked up by the pump suction for further circulation through the well. The mud fluid, thus used repeatedly in closed circuit, need only be replenished to the extent that it is absorbed by the porous formations penetrated by the well.



Redrawn with additions, from illustration in National Supply Co.'s Catalog 30.)
Fig. 30.—Plan and elevations of a 106-ft. rotary rig.

The swivel, drill stem and bit may be raised or lowered in the well by means of a steel cable operating through a massive hoisting block strung from sheaves at the derrick crown. The free end of this cable passes down through the derrick and is wound on a heavy hoisting drum sup-

ported by metal bearings mounted on three substantial oak posts. The hoisting drum is driven from a line shaft by chain belts and sprockets, with individual clutches so arranged as to provide two or more speeds. The line shaft is usually driven by a chain belt from a sprocket on the crank shaft of a steam engine, though a variable-speed electric motor can be adapted to the work through the use of intermediate gearing. Heavy band brakes on the flanges of the hoisting drum permit of suspending the weight of the drill stem and swivel when the power clutches are disengaged. On the line shaft there is also a sprocket for a chain drive, which operates the rotary table. The latter connects either directly with the jack shaft of the rotary table or indirectly through an intermediate drive shaft. The drive shaft may also support an additional sprocket for operating a mechanical mud mixer, and two cat heads useful in applying power to the heavy pipe tongs used in tightening the joints of the drill stem and for other purposes. The hoisting drum with its supporting shaft, the drive shaft, sprockets, brakes, clutches and supports are known collectively as the "draw works," commonly furnished as a unit by manufacturers specializing in rotary-drilling equipment.

The size and weight of the equipment used vary according to the diameter and depth of the hole to be drilled. Preference as between light and heavy equipment also varies in different fields. For example, the rotary equipment used in Texas and Louisiana is often lighter than that used in California.

The rotary derrick is a higher and heavier structure than the derricks described in the previous section for cable drilling but is otherwise similar in form and design. The height is often 122 ft. The space enclosed within the four legs is often 24 ft. square at the level of the derrick floor and 5 ft. square at the crown. The legs are reinforced with "doublers" for the full height, and if the well to be drilled is a deep one, sway bracing is applied on the outside of each panel between alternate girts. The engine housing is but little more than a low lean-to structure or an extension of the housing at one side of the derrick. There is, of course, no occasion for the belt house and plank walk described in connection with the standard cable rig.

A platform of 2-in. plank is built across one side of the derrick at one or more elevations, to provide the necessary footing for the derrick man in manipulating the upper ends of the "stands" of drill pipe as they are "made up" or "broken down." Such platforms are frequently extended outside of the derrick, and railings are built around the outer edge for greater security of the derrick man in moving from one side of the derrick to the other. The square space on top of the derrick about the crown block is similarly enclosed as a protection to one engaged in inspecting or oiling the sheaves or in stringing the hoisting cable over them. Such platforms and hand railings are required by law in some states as an

accident preventive. Reinforcement of the derrick floor across the side where the sections of stem are placed on end when not in the well, and suitable timber braces and guides to keep them in position in the upper portion of the derrick, are also important considerations.

A shallow cellar is excavated beneath the derrick, in which a vertical "conductor pipe" of riveted steel, corrugated pipe, or wood staves is placed and carefully plumbed and braced. A rectangular hole is cut or is left in the center of the derrick floor, of the same size and shape as

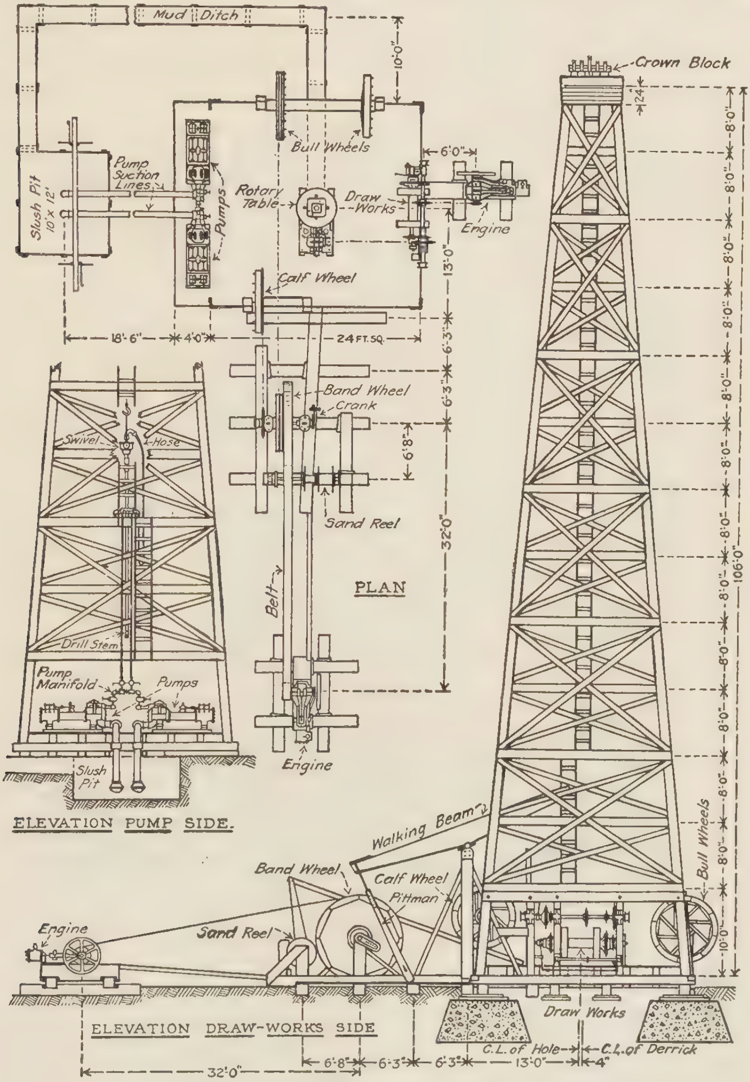
Fig. 31.—A 122-ft. rotary rig in the Oklahoma City field, Okla.

the metal base of the rotary table, a timber frame to which the table is bolted resting directly upon the derrick center sills. The latter, in turn, are supported on substantial posts resting on concrete piers or timber footings.

A mud pit of adequate capacity is excavated at one side of the derrick, conveniently placed for the pump suction lines. A wooden trough 24 in. wide and 12 in. deep, at least 125 ft. long and graded to a slight slope, is constructed about two or three sides of the derrick at or slightly above the ground level. It is arranged at one end to receive the overflow of fluid from the well and discharges at the other end into the mud pit (see Fig. 30). A supply of clay of suitable character is hauled from the nearest available source and piled ready for use at one side of the mud pit.

Combination Rigs and Methods

With a view toward securing the best features of both the rotary and cable-tool methods of drilling, many operators prefer what is called a



(*Redrawn with additions, from National Supply Co.'s Catalog* 30.)

Fig. 32.—Plan and elevations of California-type combination rig, 106 ft. high.

Note: One or more platforms with railings (not shown in drawing) are ordinarily provided around the outside of a California derrick for the safety and convenience of the derrick man. The crown block is also customarily surrounded by a suitable platform and railing. See Fig. 36*A*.

"combination rig," which includes all the essential equipment pertaining to each of the two methods under one derrick. The rotary equipment is then used when it seems best adapted to the conditions to be met, and,

when the cable tools are preferable, they will be rigged and made promptly available. In some combination rigs, the rotary and cable tools are arranged to work simultaneously.

The usual form and arrangement of the combination rig are illustrated in Fig. 32. It will be noted that there is no change in the position of any of the parts of either the rotary or cable-tool equipment. The cable tools can readily be operated through the opening in the rotary table,

(*Courtesy of Emsco Derrick and Equipment Co.*)
FIG. 33.—Typical 122-ft. California-type combination rig.

using the slips in the latter instead of a casing block. However, it is a simple matter to move the rotary table out of the way temporarily, if necessary. One end of the hoisting cable may be attached to the hoisting drum of the draw works, and the other to the calf-wheel shaft, so that the hoisting blocks may be raised or lowered from either end. The calf wheel is more powerful than the hoisting drum, because of its greater diameter and slower movement, and is therefore preferred in handling casing.

The derrick used is often 122 by 24 ft., this size being used more than any other in deep rotary drilling. The requirements imposed by the

rotary equipment determine the size and weight of the combination rig, a rig heavy enough for rotary drilling having ample strength for any strain imposed in cable drilling. However, it is customary to use a heavy derrick with ample bracing. Certain slight changes in the arrangement and number of the sheaves in the crown block are necessary.

Other arrangements of the equipment in a combination rig have been suggested and applied. One design places the draw works under the walking beam near the Samson post, driving the draw works by a chain from a sprocket on the band-wheel shaft. In this case one engine may be used and the calf wheel may be dispensed with, using the hoisting drum of the draw works to manipulate the casing when either system of drilling is employed. Occasionally the Samson post is pivoted so that the walking beam may be swung to one side out of the way of the rotary drill stem and swivel.

Comparative Advantages and Disadvantages of Rotary and Cable Systems of Drilling

On investigating the relative advantages and disadvantages of the two principal methods of drilling, we find that each has its own particular sphere of usefulness. Conditions in each individual field will determine which is best adapted. For the comparatively shallow fields of the Appalachian region of the United States, where the formations to be penetrated consist chiefly of hard, slaty shales and well-indurated sandstones, the cable tools have been and are exclusively used. The cable-tool method is also preferred by most operators in certain of the Rocky Mountain and west Texas fields where the oil sands lie at shallow depths and where hard formations must be penetrated. On the other hand, recent drilling in most of the California, Mid-Continent and Gulf Coast fields of the United States has been almost exclusively by the rotary method. Particularly is this true where great thicknesses of soft, semiconsolidated formations must be penetrated.

During the earlier years of rotary drilling there was considerable distrust of this method, and numerous arguments were advanced against its use chiefly by drillers trained in the use of cable tools who naturally disliked a process differing so radically from that which had been used since the early days of the industry. The rotary method was originally thought to be chiefly applicable to certain peculiar conditions prevalent in the fields in which it was first successfully applied, but, as its use was extended to other fields and the records attained by it became known, the rotary was eventually accepted as a real competitor of the older method. Indeed, within recent years, wherever deep drilling has been necessary, the rotary has been the preferred method, and in many of our recently discovered fields it has been used exclusively. Improvement in design and the development of hard-rock rotary bits have been largely responsible for this rapid trend toward the use of the rotary method.

When the two methods are impartially compared, it is at once evident that the rotary has certain definite advantages that make it preferable under ordinary conditions. It is more rapid, and because of this it operates at a lower cost per foot and secures production within a shorter space of time. By its use, strings of large-diameter pipe may be carried to great depths with minimum loss of working diameter and at a considerable saving in the cost of casing. It has been found possible to drill through great depths of unconsolidated sands and shales with the rotary under conditions that are practically prohibitive for the cable tools. It is simpler—much of the technic that required years of experience for the cable driller to acquire is unnecessary in rotary drilling. To be sure, successful operation of the rotary equipment requires a technic of its own, but it will be generally admitted that it is easier to acquire the art of rotary drilling than to become a skilled cable driller. The rotary operates fairly continuously, without interruption for bailing, and with a fewer number and a smaller variety of fishing jobs. Use of the circulating fluid provides a means of controlling high gas and water pressures often encountered in drilling for oil and makes possible the carrying of open hole to great depths so that the well does not have to be cased until the particular size of hole being drilled is completed. Furthermore, there is greater freedom of the casing in the well, and the landing depths and water shut-offs can be more definitely planned and the work carried forward with greater certainty of completion according to predetermined schedules. Action of the cable tools is severe, often fracturing the walls so that they cave readily. The hole drilled by the rotary, on the other hand, is clean cut, with a minimum of fracturing of the walls, and the hole is necessarily always round so that the casing passes freely through.

While there is much to be said in favor of the rotary method of drilling, there are some disadvantages that favor the cable method under certain conditions. Probably the greatest disadvantage that can be urged against the use of the rotary is the difficulty encountered in determining the character of the formations penetrated. It is essential that accurate data be secured for the well log, and in many cases the drilling returns brought to the surface in the sludge with the rotary equipment are so finely pulverized and contaminated with mud that they cannot be definitely classified. The color of the sludge, the presence or absence of sand and grit, effect of the formation on the bit and the manner in which the drill stem, table and mud pump behave, are about all that the driller has to work on in securing data for the log. With the sandstones and harder rocks it is possible to secure a fairly good sample which can be washed free of mud from the mud ditch, but the presence or absence of argillaceous material in the formation can only be surmised since it is usually so finely ground that it is inseparable from the circulating fluid when it reaches the surface. With the cable tools, on the other hand, it

is possible to get a fairly definite idea of the nature of the rock in which the drill is operating by an examination of the material brought up by the bailer, and often large fragments of the material will be found adhering to the bailer or to the drilling bit when it is withdrawn. The disadvantage of the rotary in this respect has been largely offset during recent years by the more general use of rotary core-drilling devices which give the driller an actual sample of the material in the bottom as it occurs in place.

Another disadvantage frequently urged against the use of the rotary is that the circulating fluid used tends to seal off the sands encountered, commercial oil sands being sometimes mudded off so effectively that the operator drills through them without becoming aware of the presence of oil. This is a particularly serious criticism in the drilling of pioneer wells in a new field, or wherever the exact depth of the oil sands to be encountered is uncertain. Even in partially developed fields where the position of the productive sands is definitely known, the oil-sands exposed in the well are frequently so clogged with mud that the well never attains normal productivity. Many irregularities in the productions of adjacent wells can be explained on this basis. Such difficulty, however, is largely due to unskillful drilling, or failure to wash out the clay sufficiently after completion of the well, and is therefore not a logical argument against the use of the rotary method. It is also claimed by some proponents of the cable method that, if the oil sands are under low gas pressure, considerable water may be permitted to enter from the well, partially flooding the sand and reducing its normal productivity. It seems probable, however, that the mudding action of the circulating fluid would prevent any great quantity of fluid from entering the oil sand; furthermore, it should be readily drained from the area about the well by a few days of pumping after the well is completed.

While many drillers will question this statement, it is probable that rotary holes are more frequently crooked than wells drilled by cable methods. However, crooked holes may be largely eliminated by more careful drilling methods, particularly by the use of lower bit pressures.

Unless hard-rock bits are available, the rotary makes very slow progress in hard sandstones and limestones. The fishtail bit is rapidly dulled in such rocks, and much time is lost in withdrawing and replacing the drill stem in changing bits. The cable tools may be withdrawn from a 3,000-ft. hole in 5 min., but 1 hr. or more will be necessary to remove a rotary bit. Use of the hard-rock bits will partially offset this disadvantage of the rotary, however.

The rotary equipment has a greater first cost than a cable-tool rig, and if the hole to be drilled is a shallow one, the additional cost of the rig will offset any advantage which the rotary may possess in reduction of casing expense or cheaper unit drilling cost. A standard cable rig has a

much lower daily operating cost because of the fewer number of men employed, and because it requires less power; hence, unless the rotary equipment can show a marked superiority in footage drilled, its advantage from the standpoint of unit cost is lost.

Water supply and transportation are troublesome factors in some regions. Here again the standard method has the advantage, the equipment being more readily transported and requiring considerably less water for drilling and steam-raising purposes.

Summarizing the arguments given above for and against each of the two methods of drilling, it would appear that the rotary method is superior when the oil-producing strata lie at considerable depth and their position is definitely known, when the formations to be penetrated consist mainly of soft and moderately soft rocks, and when formations containing high-pressure gas are expected. The standard cable method, on the other hand, is sometimes preferred in drilling "wildcat" wells where the geologic conditions and stratigraphic sequence are uncertain, and where accurate information for the well log is especially important. The cable tools are generally preferred if any great thickness of hard rock is to be penetrated, or where the productive horizons are found at shallow depths. Cable tools are often used in finishing wells drilled primarily with rotary equipment, particularly if the oil sands are under low pressure, because of the danger of mudding off the productive strata by use of the latter method.

DERRICKS

With the exception of portable and semiportable drilling rigs used only for drilling comparatively shallow wells, all systems of drilling require the provision of some form of derrick. In a chapter devoted to the general features of drilling equipment we may therefore appropriately discuss the factors entering into derrick design and erection and the selection of materials employed in their fabrication.

A derrick comprises four upright members called "legs," forming the corners of the structure, these being tied together by horizontal "girts" and inclined "braces." The structure as a whole should possess rigidity and should be capable of supporting loads of considerable magnitude when suspended on cables passing over sheave wheels mounted on the top or "crown." All four sides of the derrick are battered to a slope of 1 in 5 to 1 in 7, depending upon the height and the size at the bottom and top. The derrick is supported on short posts, which rest, in turn, upon timber "footings" or concrete piers. The posts also support the "sills," on which rest the wooden plank flooring and heavier metal drilling equipment.

In addition to supporting the various tools, wheels and cables in position, derricks have the function of providing something to pull

against in handling the long lines of heavy tools and casing, aggregating at times hundreds of tons in weight. On account of the great strain put upon it, the derrick must be well braced in all directions and securely anchored on firm foundations so that it will not collapse or be pulled over. It must be high to provide between the sheaves at the crown and the mouth of the well at the derrick floor sufficient head room in which to manipulate the long strings of drilling tools, casing and hoisting tackle.

Derricks may be constructed of either wood or steel. Common pine and hemlock are generally used in the construction of wooden derricks in the American fields. Harder woods, such as oak, beech or maple, are used at times in certain of the posts, sills, wheels, shafts, crown blocks and other members subjected to great strain or wear. Rarely, creosoted timber will be used. Steel derricks may be constructed either of the usual rolled sections—angles, channels, I-beams, etc.—or of tubular forms. For housing the lower portion of the rig and derrick, galvanized corrugated sheet iron is often used instead of wooden sheathing. While somewhat more expensive than wood, galvanized sheet iron is fireproof and longer lived. The derrick footings may require the use of concrete, though they are often built entirely of wood.

Until 1927, there was little uniformity in the design and dimensions of derricks used in the oil fields. About this time, the American Petroleum Institute, as a phase of its standardization program, adopted a group of standard specifications for oil-field derricks. As a result, where there were formerly several hundred different sizes of derricks manufactured in this country, there are now only 12 that have been adopted as standard. Table XIII gives the principal dimensions of the A.P.I. standard sizes.

Table XIII.—Dimensions of A.P.I. Standard Derrick Sizes

Height, measured along leg, ft.	Base squares		Water-table openings, in the clear
	Regular series, ft.	Uniform taper series	
136	26	. . . .	5 ft. 8 in.
122	24	26 ft. 0 in.	5 ft. 6 in.
94	24	21 ft. 5 in.	5 ft. 6 in.
87	24	20 ft. 3¼ in.	5 ft. 6 in.
80	20	19 ft. 1⅜ in.	5 ft. 6 in.
73	20	16 ft. 9⅞ in.	4 ft. 4 in.
66	20	. . . .	4 ft. 4 in.

Prior to the adoption of these standard sizes, the industry had developed the practice of maintaining certain standard sizes for the bases of derricks, generally, 20, 22 or 24 ft. Derricks of different height were adapted to these bases by slight changes in the taper or slope of the

sides of the structure. In deference to this earlier practice, the "regular" series of derrick sizes, adopted as standard by the American Petroleum Institute, still makes use of the 20-, 24- and 26-ft. base square, the size increasing with the height. In addition to the regular series, the A.P.I. has also adopted a second series of sizes known as the "uniform-taper" series, in which the batter of the tower remains constant throughout all sizes, each different height of derrick requiring a different size of base. The size of the opening through the water table at the summit of the derrick is also specified in order that crown blocks of different manufacturers—also rigidly specified as to size—will fit any derrick.

Of the different sizes of derricks adopted as standard, only the larger three are appropriate for rotary drilling. The most widely used size of the three is the 122-ft. derrick, though of late some operators in the very deep fields have been specifying 136-ft. derricks. Earlier rotary drilling in the shallower territory in many instances made use of 106-ft. derricks similar to that represented in Fig. 30. This size, however, is no longer standard. The 94-ft. derrick is appropriate for rotary drilling only in the comparatively shallow fields. For cable drilling, most operators would probably prefer the 73- or 80-ft. tower, the 87-ft. derrick being necessary only in the drilling of unusually deep wells. The 66-ft. derrick is primarily a "production derrick," though it may be used for cable drilling in shallow territory. There has been limited use of 166-ft. derricks in rotary drilling in western American oil fields, and in one instance a derrick 178 ft. high and 32 ft. square at the base was used.

Selection of the size of derrick is governed primarily by considerations of economy in installation cost and saving of time in handling long strings of tools, drill pipe and casing. In deep drilling, very heavy hoisting blocks and hooks must be used, and these, being longer than the lighter equipment designed for drilling to shallower depths, require more head room. In rotary drilling, the higher derricks permit of handling longer stands of drill pipe, thus expediting the work of withdrawing and inserting drill pipe. This advantage is especially important in deep drilling, where a considerable percentage of the total time available for drilling is spent in changing bits.

In selecting a type of derrick appropriate for his purpose, the oil producer must consider not only its utility in drilling the well but also its adaptation to subsequent repair and cleaning operations during the period of production. A full-sized rotary derrick is much larger and heavier than will be necessary for subsequent maintenance of the well, and in order to recover a part of the investment in the heavier and larger structure needed during the drilling stage, some operators disassemble the drilling derrick when the well is finished and substitute a smaller and lighter operating derrick. The larger structure may thus be used repeatedly and exclusively in drilling operations. Tearing down and reassembling

derricks in this way is less feasible with timber derricks than with steel derricks.

When the drilling derrick is replaced by an operating derrick, it is often important that the well should not be without a derrick for any length of time, as in case of accident or any other emergency there would then be no means of manipulating tools or heavy fittings in the well or about the casing head. Some operators erect the smaller operating derrick inside the drilling derrick before the latter is removed. One style of steel derrick is so designed that after the well is completed the upper portion of the tower—generally the upper 84 ft.—can be detached from the lower portion and lowered integrally through it with the aid of blocks and some additional steel work supported by the lower members. The 84-ft. operating derrick rests on a 20-ft. square inner section of the original 26-ft. base provided for the higher structure. The lower portion of the drilling derrick is then removed and may be used in the drilling of another well, in combination with a new 84-ft. top. These interchangeable features, of necessity, require the use of the uniform taper series of sizes (see Table XIII).

Design of Derricks

The loading on an oil-well derrick is complex, often eccentrically applied and consequently difficult of analysis. The legs are, of course, always under compression, though important bending stresses may be imposed at times. The dead weight of the structure imposes very little stress on the girts and braces, but when wind load and the live load involved in operating drilling equipment, handling casing, etc. are applied, the horizontal and inclined members are subjected to stresses the magnitude of which depends upon the nature and direction of application of the load and the position of the member in the structure. Generally, the horizontal girts are subjected to compressive strain, while the inclined braces assume the tensional loads. In addition, the individual panels are subjected to bending stresses and torsional strain, as, for instance, when tension is applied in a cable suspended from an off-center sheave in the crown block, toward one side of the structure. At times, in certain phases of the drilling process, impact loads and severe vibrational strains are imposed. Though the loading is complex and varies considerably with the character of the live load imposed, it is possible to approach the design of a derrick by graphical or mathematical analysis and proportion each member of the structure in accordance with the maximum stress that it will be called upon to sustain in normal drilling operations.

In selecting derricks for drilling purposes the engineer must consider the maximum loading likely to be imposed. Generally, the greatest dead load that the derrick will be called upon to support is that of the heaviest column of casing to be inserted in the well. This, of course, can be com-

puted if the size and landing depth of each "string" of pipe to be used can be determined in advance. To the dead load of the casing a friction allowance of 25 or 50 per cent should be added. For example, if 5,000 ft. of 10¾-in., 45.5-lb. casing is to be set, and 1,250 ft. (25 per cent) is added to cover friction, the probable dead load imposed on the derrick will be 6,250 × 45.5 = 284,375 lb.

Manufacturers marketing A.P.I. standard equipment are now required to rate their derricks according to the maximum dead loads that they are designed to support. The engineer has merely to refer to the manufacturers' tables giving ratings for the different sizes and weights of derricks to select the one appropriate for his needs. Manufacturers customarily use a safety factor of from two to four in designing derricks, so that the ultimate load at which a derrick will actually fail is generally at least double the rated safe load. Table XIV gives the ratings for

TABLE XIV.—A.P.I. DEAD-LOAD CAPACITIES OF STRUCTURAL-STEEL DERRICKS*

Size of main leg angle, in.	Size of reinforcing pipe	Capacity unreinforced		Capacity reinforced	
		Mild steel, lb.	High-tension steel, lb.	Mild steel, lb.	High-tension steel, lb.
3½ × 3½ × ¼	3 in. × 7.62 lb.	66,800	100,200	191,160	320,700
4 × 4 × ¼	4 in. × 10.89 lb.	85,700	128,550	275,900	466,050
5 × 5 × ¼	4¾ in. × 15 lb.	126,400	189,600	388,800	655,600
5 × 5 × ⅜	4¾ in. × 15 lb.	186,000	279,000	448,400	745,000
6 × 6 × ⅜	4¾ in. × 15 lb.	246,000	369,000	508,400	835,000
6 × 6 × ½	4¾ in. × 15 lb.	323,000	484,500	585,400	950,500
6 × 6 × ⅝	4¾ in. × 15 lb.	398,000	597,000	660,400	1,063,000

Note: The high-tension steel has a yield point approximately 1.5 times that prescribed for ordinary mild steel.

* From data furnished by Emsco Derrick & Equipment Company, Los Angeles, Calif.

A.P.I. standard steel derricks marketed by one American manufacturer. It will be noted that this manufacturer uses two different materials in the construction of derricks: the ordinary mild structural steel having a tensile strength of about 50,000 lb. per square inch, and a special steel of higher carbon content, having a tensile strength 50 per cent greater than that of ordinary steel. With the latter material a lighter derrick may be selected for the same loading.

Maximum strain is imposed on the derrick in pulling on "frozen" casing, and some engineers select derricks strong enough to resist a tensional strain sufficient to pull the casing apart. For example, 10¾-in.,

45.5-lb. medium-carbon seamless casing has a maximum joint pull-out strength of approximately 490,000 lb. Table XXXIII, page 303, shows computed pull-out strengths of various sizes and weights of A.P.I. standard casings.[13]

Another method of estimating the necessary dead-load strength of a derrick is to assume that it must be capable of withstanding the strain necessary to break the hoisting cable. Table XVI, page 155, gives maximum ultimate strengths of various grades of 6 by 19 and 6 by 7 wire ropes. If, for example, a 1 in., 6 by 19 grade L cable is strung with nine lines between the crown block and the hoisting block, the maximum dead load to which the derrick can be subjected will be approximately 9 times 68,000 lb., or 612,000 lb.

The wind load imposed on a derrick is often considerable, though not so great in the case of a steel derrick as in the case of a timber structure because of the smaller cross section of material exposed to the wind. Derricks are often designed to withstand an applied wind velocity of 70 m.p.h., which is equivalent to a horizontal pressure of 11.76 lb. per square foot on the entire surface exposed. In computing the surface exposed to the wind, it should be assumed that the wind pressure is brought to bear on the outside of one panel and on the inside of the opposite panel. American Petroleum Institute specifications also require that in computing the effective wind load, it be assumed that a "set-back" of pipe of a specified size is leaning against the "finger-board" of the derrick at an angle of 5 deg. from the vertical. For a 122-ft. derrick, the set-back is considered as 36 stands of 6-in., 25-lb. rotary drill pipe, 90 ft. long, forming a 6- by 6-ft. square. For the 94-ft. and 80-ft. derricks, a set-back of the same size, but 67.5 ft. long, is assumed. The influence of wind pressure on the structure as a whole is offset by bolting the four legs securely to the foundation piers.

Though a properly designed derrick is supposed to be self-supporting, most operators prefer to guy them to near-by stationary objects on the ground or to "dead men" of timber, steel or concrete buried in the earth, usually about 150 ft. distant. From 8 to 24 guy wires are used, that is, from two to six on each leg. These are attached at two or three points between the derrick crown and the floor and are led off from the structure in the direction of the diagonal plane through the opposite leg. Guy wire is appropriately ⅜ in. in diameter and composed of seven strands of galvanized wire.

In its Standard Rig and Derrick Specifications, the American Petroleum Institute recommends use of the following formula in computing wind-load pressures: $P = 0.0024V^2$, in which V is the assumed or estimated velocity of the wind in miles per hour, and P is the pressure exerted, in pounds per square foot of exposed area. For example, a 120 m.p.h. wind exerts a pressure of 34.56 lb. per square foot of exposed surface.

This is about the maximum likely to be attained in most regions, and some manufacturers design their derricks to provide security against this amount of horizontal pressure.

The load imposed on a derrick may at times be in excess of the rated safe working load. Handling long strings of heavy casing or pulling on frozen drill pipe or casing with powerful twin-cylinder engines operated under high steam pressure, with the force multiplied many times by massive hoisting blocks, with loads often suddenly applied, imposes a strain which occasionally causes buckling or even complete collapse of the derrick. In analyzing the loads applied, we have to consider first the dead load of the derrick itself, which in the case of a 122-ft. steel derrick may reach 40,000 to 50,000 lb. A long column of heavy casing may weigh as much as 300,000 lb., to which should be added at least 25 per cent, or another 75,000 lb., to cover friction in handling. In pulling on frozen pipe, an additional load may be imposed by the line pull from the engine and draw works or calf wheel, of perhaps 20,000 lb. This may be multiplied as many as 11 times by the hoisting block, producing a total live load of as much as 220,000 lb. This load is, perhaps, quickly applied and is therefore productive of impact stress, for which a high safety factor must be imposed. Though the wind load is generally regarded as being applied at right angles to the side of the derrick, it is resolved by the guy wires or foundation bolts into compressive strain on the derrick legs. If we assume a unit pressure of say 30 lb. per square foot applied on both sides of the derrick, over a total area of about 425 sq. ft. for each, and upon a setback of drill pipe presenting an additional area of about 360 sq. ft., wind pressure alone may exert a strain of about 30,000 lb. This, too, is an impact load in that it may be suddenly applied.

The aggregate of these various loads may reach surprising totals if simultaneously applied and if appropriate multipliers are used to evaluate properly the effects of impact stress. Authorities generally agree that impact loads, due to the suddenness with which they are applied, develop stresses as great as four or five times the actual force exerted. If we apply a factor of four to the impact forces suggested in the preceding paragraph, we may attain a maximum strain equivalent to a dead load of 1,425,000 lb., or upward of 700 tons, in the event that the different possible loads are applied simultaneously. This, however, is a maximum figure, and it would be quite unusual for all of the possible loads to be applied simultaneously. Such a load would exceed the heaviest permissible loading for even the heaviest of derricks.

Having determined the maximum dead load to which a derrick is likely to be subjected, the necessary minimum cross section of the main compression members or legs is determined by dividing the total load by four and substituting this value for P in the following equations:

$$(1) \qquad \frac{P}{a} = 15{,}000,$$

if ratio of l/r is not in excess of 60;

$$(2) \qquad \frac{P}{a} = \frac{18{,}000}{1 + \dfrac{l^2}{(18{,}000)(r^2)}},$$

if l/r is greater than 60.

In these equations P is the total compression load in pounds; a is the gross cross-sectional area of the derrick leg in square inches; l is the unsupported length of the column or leg element between adjacent panel points in inches; and r is the corresponding least radius of gyration of the column cross section in inches.

Derrick Foundations

To distribute loading properly and to keep all mechanical equipment in proper alignment, the derrick should be provided with a rigid foundation. This may be of either timber or concrete, but the latter material is preferable, especially if the well to be drilled is a deep one and heavy loads are to be imposed. The size of the foundation to be provided may be determined only after an inspection of the subsoil upon which the foundation is to rest. Alluvial soil is capable of supporting a load of only 1,000 lb. per square foot without yielding; soft clay or wet sand, 2,000 lb.; firm, dry loam, 5,000 lb.; compact sand, gravel and boulders, 10,000 lb.; rock, 30,000 lb. Having estimated the total dead load of the derrick and the live load to which it will be subjected, the total is divided equally among the four legs and a footing constructed for each leg having a base of such size as will distribute the load over an area of subsoil capable of supporting it. It is very important that the foundation be absolutely rigid and unyielding, for if one corner yields under strain the total load is thrown on the two adjacent legs and failure of the structure may result. It is said that most derrick failures are caused by unequal loading of the derrick legs, caused by subsidence of some part of the structure under strain. It is claimed that wooden derricks adjust themselves better to slight changes in the position of the foundations than steel derricks, owing to their greater flexibility and ability to yield without failure.

Wooden derrick footings are generally constructed of heavy timbers, often 8 by 10 in. or larger, nailed together to form a pyramidal structure of appropriate height and with a base of such size as to spread the load over a sufficient area. The base of the footing is preferably buried in the earth sufficiently to minimize the tendency of the subsoil to shift or flow under the load imposed. The derrick footing cannot yield unless the soil is pressed out from beneath it. Soil, sand or gravel yields more

readily wet than dry, hence proper drainage of the subsoil under the derrick footings should receive attention. This may be accomplished to some extent by simply heaping the soil from the excavation to form a mound about the footing. Gravel tamped into the excavation about the timber provides a firmer base in soft soils.

Concrete derrick footings are of various forms, often reinforced with steel wire mesh to distribute the load over the entire area of the base and to offset the tendency of the pier upon which the derrick leg rests from

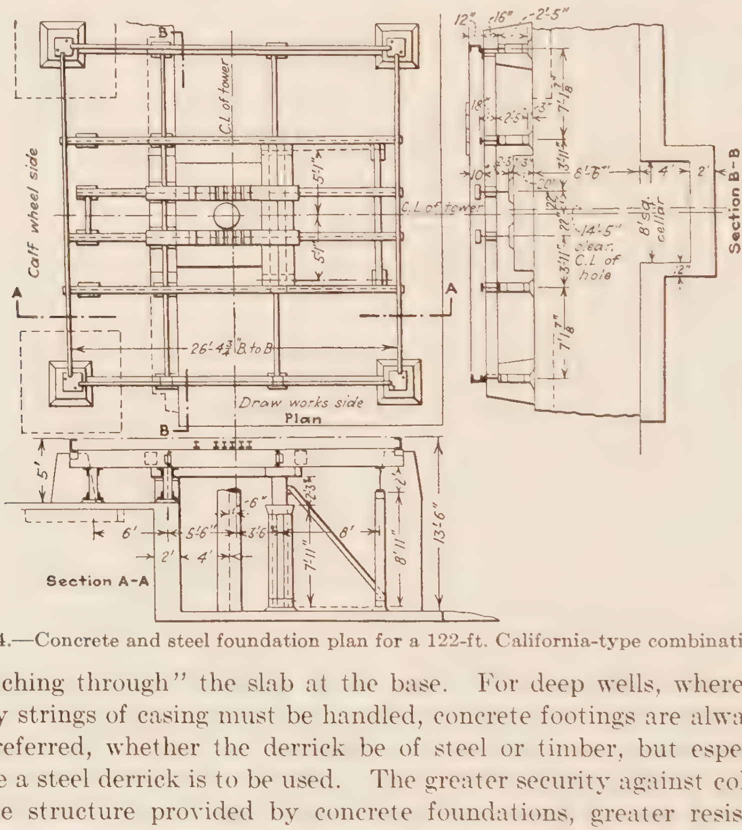


FIG. 34.—Concrete and steel foundation plan for a 122-ft. California-type combination rig.

"punching through" the slab at the base. For deep wells, where long heavy strings of casing must be handled, concrete footings are always to be preferred, whether the derrick be of steel or timber, but especially where a steel derrick is to be used. The greater security against collapse of the structure provided by concrete foundations, greater resistance against decay and better distribution of strain among all parts of the rig assure longer life to the derrick, lower maintenance costs and, most important of all, safety of personnel.

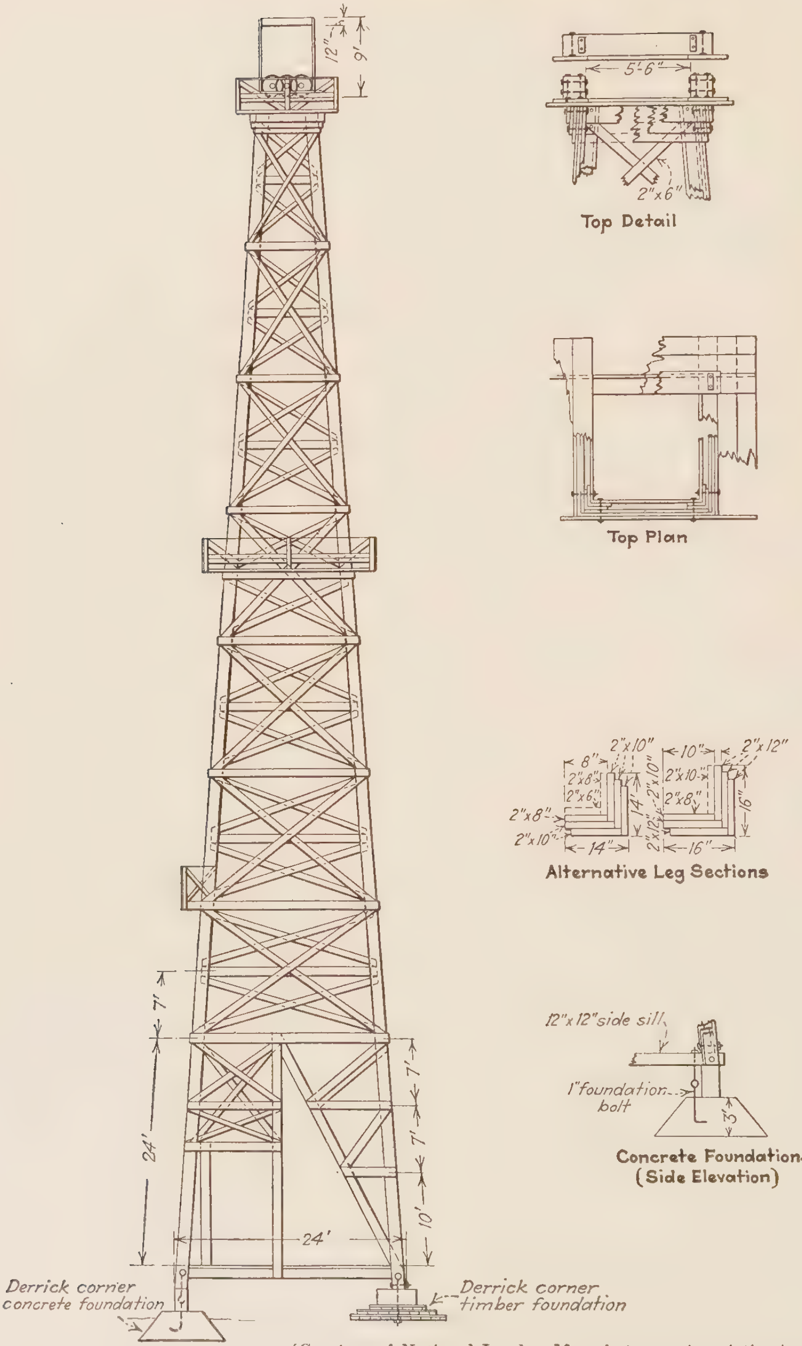
DERRICK TYPES

We may conveniently classify derricks according to the form and nature of the material of which they are constructed. Thus we have timber derricks and steel derricks, the latter being constructed either of structural steel or of tubular forms. Another type, known as a "turnbuckle rig," makes use of both timber and steel.

Timber Derricks.—Until rather recently, practice in the construction of timber derricks was based largely upon precedent. Little or no scientific design, in which different members are proportioned to the loads applied, entered into their construction. The National Lumber Manufacturers Association, however, has given attention to this subject, and improved designs have been developed, based on physical tests, assuring greater strength and economy in use of material.

Legs of wooden derricks are usually constructed by nailing 2-in. plank together to form a right-angled, trough-shaped member. In heavy derricks each leg has often been constructed of one 2- by 10-in. plank and five 2- by 12-in. planks. However, tests have shown that a derrick leg made of one 2- by 8-in. plank and five 2- by 10-in. planks is actually stronger, though of smaller cross section (see Fig. 35). This is believed to result from a little known characteristic of wood-compression members, by which those wider in horizontal cross section than 4½ times their thickness fail in torsion rather than by direct column action. Derricks of lighter construction, appropriate only for drilling to shallow depths with cable tools, make use of considerably less timber, the cross section sometimes consisting of only two 2-in. planks. In drilling to greater depths, a second or outer pair of planks called "doublers" are frequently used to reinforce the lower part of each leg. The horizontal girts and inclined braces are also of 2-in. material, 6, 8, 10 or 12 in. wide, depending upon the place of the member in the structure. In addition to the usual braces and girts nailed on the inside of the derrick legs, heavy timber derricks requiring additional strength are "sway braced" by adding a second set of girts on the outside of the legs opposite every alternate set of inside girts and placing long diagonal braces between the outside girts (see Fig. 32). The engine and belt house are often built of 1- by 12-in. lumber on a light timber frame, and the housing about the lower part of the derrick may also consist of light wooden sheathing. Many operators, however, prefer corrugated sheet iron for housing in the engine house, belt house and such part of the derrick as may require protection from the weather. For the walk connecting the derrick and engine house and the flooring throughout the structure 2-in. planks are used. A rack of 6- by 8-in. timber built beside the elevated walk is provided for the support of casing, drill pipe, tubing, tools and miscellaneous equipment.

A well-constructed 122-ft. timber derrick for rotary drilling, with flooring and all necessary sills, ladders, etc., will contain about 26,000 ft.b.m. of lumber. About 30,000 ft.b.m. will be required for a 136-ft. derrick. A 74-ft. derrick, appropriate for cable drilling to moderate depths, requires about 20,500 ft.b.m. Figure 29 illustrates a typical timber derrick suitable for cable drilling. Figures 30 and 32 are illustrative of heavier and larger timber derricks appropriate for light rotary and combination rigs. Figure 35 gives structural details of an improved



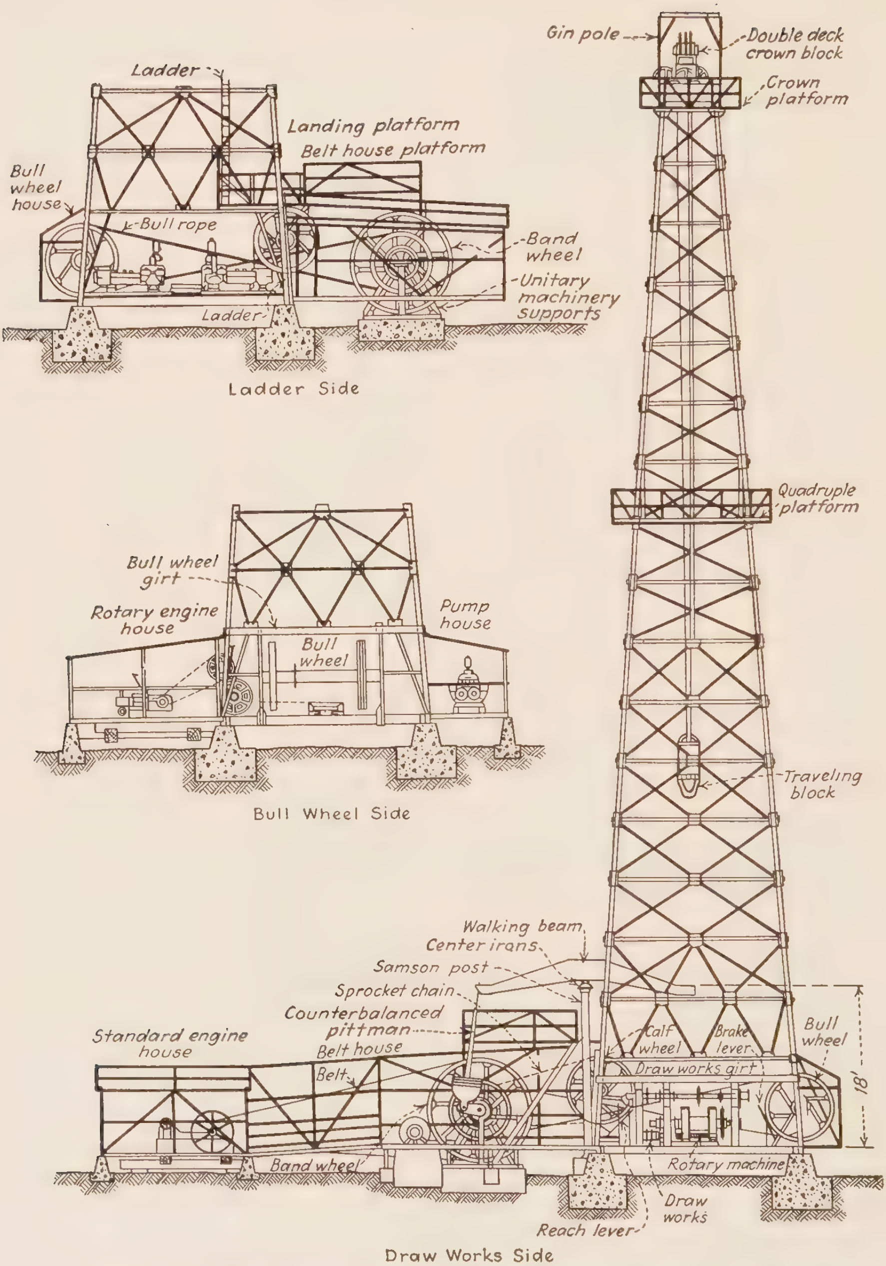
(*Courtesy of National Lumber Manufacturers Association.*)

FIG. 35.—Side elevation and structural details of a 122- by 24-ft. timber derrick.

design for a 122-ft. timber derrick, a size that has been widely used in recent rotary drilling in some of the deeper western American fields.

Structural Steel Derricks.—For drilling deep wells with rotary tools many engineers have recently shown a preference for steel derricks. Most of these are constructed of the ordinary rolled forms, generally of mild, low-carbon steel, though occasionally of steel of higher tensile strength having higher-than-normal carbon content (see Table XIV). In one popular steel derrick of this type, the legs are constructed of heavy angles, the 6- by 6- by 3⁄8-in. and 5- by 5- by 3⁄8-in. sizes being used in the larger and heavier structures, while the girts are steel angles ranging from 5 by 5 by 3⁄8 in. to 2½ by 2½ by 3⁄16 in. in size, depending upon their position in the structure. The diagonal braces are of 2- by 2-in. angles, 1⁄8 or 3⁄16 in. thick. The first five panels are double diagonal braced, and struts are used to stiffen the bracing from the fifth panel to the crown. This feature is said to give the structure unusual rigidity and reduces vibration (see Figs. 36*A*-*B*). For greater strength, structural steel derricks are reinforced with casing, set inside the angle of the legs and clamped thereto, extending from the derrick footings to the crown. One manufacturer uses 5-in., 15-lb. casing for this purpose and reports that the weight-supporting capacity of the derrick is increased 2.5 times by this means. At two elevations in the derrick, at about 40 ft. and 72½ ft. above the floor, platforms protected with guard railings are provided for the use of the derrick man in handling pipe and equipment. The "crow's-nest" at the summit of the derrick is also surrounded by a 3-ft. railing. A steel ladder-way in eight offset sections, which may be equipped with guard screens for additional safety, provides a means of ascending to any part of the structure (see Fig. 33). A 24- by 122-ft. combination rig and derrick of this type, together with steel housing, weighs about 61,000 lb.

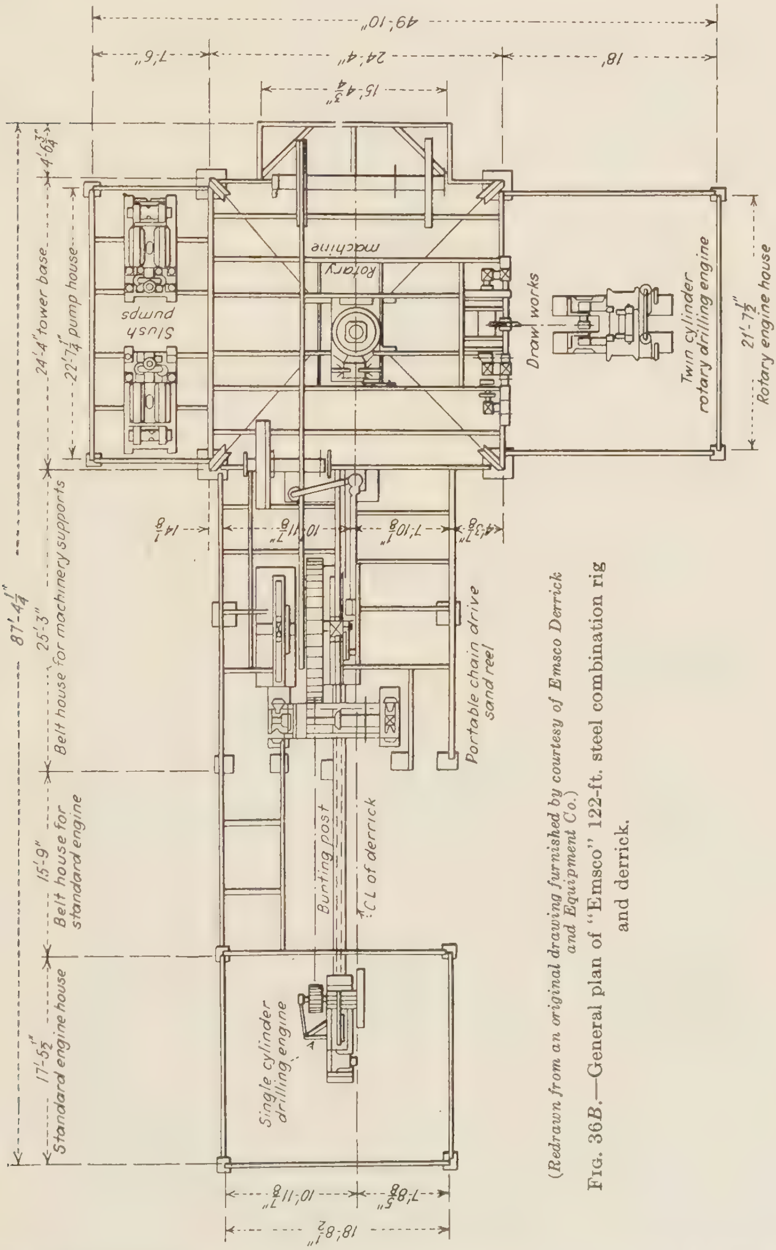
Tubular steel derricks make use of pipe forms in all parts of the structure. This type of derrick has attained considerable popularity in some districts and is preferred by some operators to steel derricks built of structural forms. The legs of these tubular steel derricks are made of steel pipe of varying weight and size, depending upon the position of the member in the structure. Tubular derricks of duplex or triplex design have one or two pipes telescoped within the leg tubes to give additional strength. One popular make of tubular derrick provides reinforcement for the legs by an additional set of tubular members bolted to the side of each leg by specially designed clamps. Adjustable screw jacks are employed on the reinforcing members to assist in securing a uniform distribution of the load. In heavy combination rigs of the California type, one manufacturer uses either 4-in. 15-lb. or 4-in. 27-lb. pipe, and, if reinforcement is required, a 3-in. pipe, bearing its share of the load, is telescoped within the larger pipe. The girts and braces are of 2 or 2½-in.



(*Redrawn from an original drawing furnished by courtesy of Emsco Derrick and Equipment Co.*)

Fig. 36*A*.—"Emsco" 122-ft. steel combination rig and derrick, side elevations.

pipe. Special clamps provide a means of attaching the girts and braces to the derrick legs. For high strength, a steel of 0.40 to 0.50 per cent

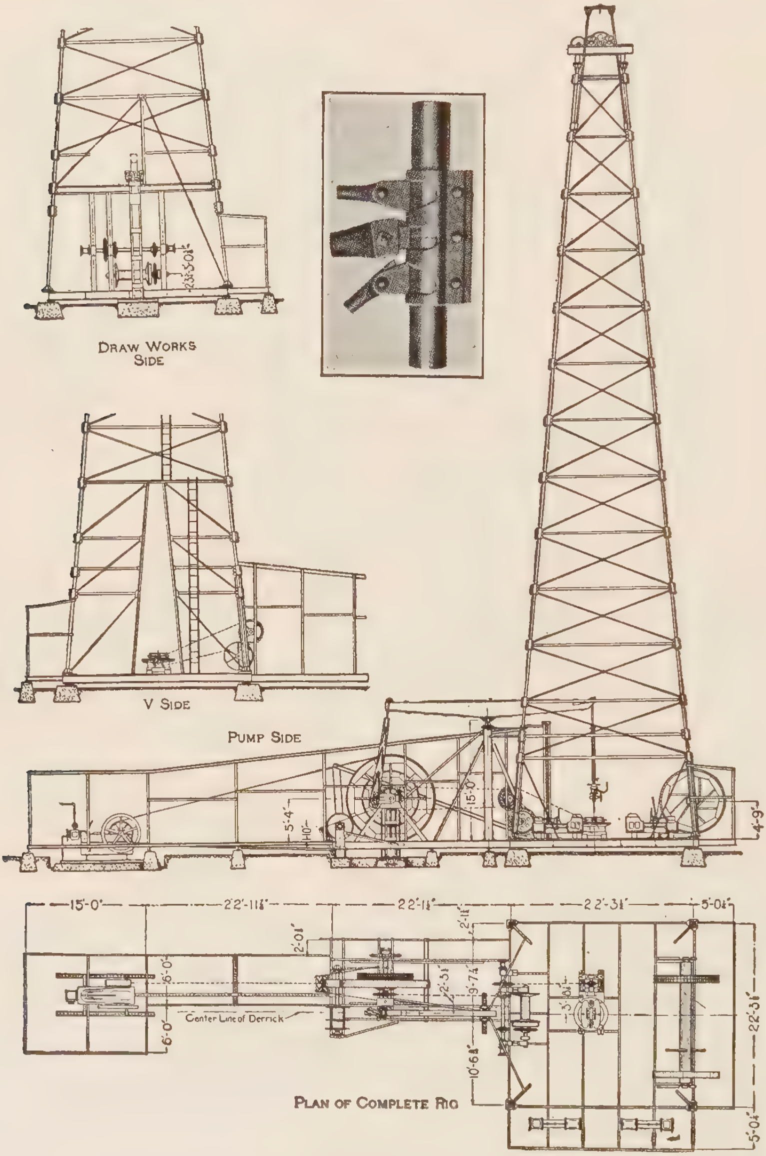


(Redrawn from an original drawing furnished by courtesy of Emsco Derrick and Equipment Co.)

Fig. 36*B*.—General plan of "Emsco" 122-ft. steel combination rig and derrick.

carbon is sometimes used. A 24- by 120-ft. combination rig of this type, including steel wheels and walking beam, may weigh as much as 83,500 lb.

(see Fig. 37). Ordinary heavy-duty rotary derricks of the same height weigh about 32,500 lb. Smaller and lighter tubular steel derricks,



(*Lee C. Moore Co., Pittsburgh, Pa.*)

FIG. 37.—Tubular steel derrick and combination steel rig.
Half-tone insert shows detail of derrick leg joint.

popular in many fields, are often used at operating wells. These are designed for use in occasional repair and cleaning operations but are not heavy enough or high enough for drilling operations.

Turnbuckle Rigs.—Various combinations of wood and steel in the construction of derricks have been worked out, with the primary purpose of facilitating dismantling and reassembling at a new site. One of these, that has been used to some extent in exploration work, makes use of timber legs and girts, with braces made of round steel rods. The braces are in two parts connected by substantial turnbuckles which permit of adjustment so that these members assume a large part of the strain. At the leg joints all members are bolted together through metal angle plates.

Advantages and Disadvantages of Timber and Steel as Derrick Materials

The relative advantages and disadvantages of timber and steel as derrick materials have of late been given careful attention by oil producers. The steel derrick is for a given weight stronger and more dependable under severe stress. Because of the opportunity for more accurate design in proportioning the various parts of a steel rig, this type is lighter than the wooden derrick by 25 or 30 per cent. It is claimed that the collapse of a properly erected steel derrick, even under severe working conditions, is very improbable; it may bend or buckle, but it is not easily collapsed in a manner to endanger personnel. This gives a feeling of security to those employed under it that is not always enjoyed when working under a timber derrick. Wind pressure on a timber derrick is about three times that on a steel rig, owing to the greater surface exposed by the former (compare Figs. 35 and 36*A*). The strength of a timber derrick depends largely upon the skill and knowledge of the rig builder. An imperfectly fitted or nailed member, or timber of inferior quality in a vital place—and the derrick will perhaps fail under strain. Steel is more uniform in its properties, more dependable; and workmanship in a well-conducted manufacturing plant is likely to be more dependable than that to be found in rig builders "picked up" in the field. The steel structure has a longer life, if properly protected by galvanizing or by occasional painting. Wooden derricks, on the other hand, are subject to deterioration, rapid in some climates, as a result of weathering and attack of termites. From the standpoint of fire risk, the steel derrick also enjoys a considerable advantage and carries a lower insurance premium. Creosoted timber, sometimes used because of its greater resistance to decay, offers a greater fire risk than untreated timber. Again, if there is prospect of a derrick being moved from one location to another, as in exploration work, the steel derrick is much to be preferred. Overtoppling or tearing down a timber derrick with the removal of the heavy spikes used in construction is likely to cause considerable damage to the timber members, while the steel structure, being fastened together by bolts, is readily disassembled and has a high salvage value. The steel derrick affords

more rigid support for the crown block, wheels and moving parts of the equipment, with better opportunity for maintaining alignment, and consequently assuring more efficient power transmission. With proper foundations, the steel derrick permits of more uniform distribution of the load.

In considering the advatages of timber, a derrick of this material is considerably lower in initial cost than steel. Rig timber is readily available in most fields and does not have to be specially manufactured in a distant manufacturing establishment. Wooden derricks, if properly constructed of selected material on firm foundations, can be amply strong for all purposes. Owing to its greater resiliency and elasticity under strain, it is claimed that a wooden derrick acts as a shock absorber and that there is less wear and tear upon the drilling equipment than is the case with a steel derrick. Many cable drillers prefer the wooden derrick because there is less vibration; it is more flexible than steel and responds better to the churning motion of the tools. While admitting that timber derricks offer greater fire risk in a general conflagration, proponents of timber as a derrick material point out that gas is sometimes ignited by sparks resulting from rocks or metal equipment striking on the steel of the derrick, and that in the event of a serious fire no material is immune. Though timber depreciates with age, it is pointed out that wooden derricks often have a longer life than the wells that they serve.

Whatever may be the merits of the argument set forth in the above paragraphs, it must be recorded that in spite of the greater cost, oil producers have been showing a decided preference for steel derricks in recent years, particularly in the deeper fields.

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CHAPTER VI

CHURN-DRILLING EQUIPMENT AND METHODS

The principal features of the churn-drilling methods and the most used representative of this group, the American standard cable system, were described in Chap. V. The present chapter will be devoted for the most part to a more detailed description of the component parts of the American standard cable drilling rig, to a consideration of their functions and relationships, their manipulation and control in the routine of drilling and the results secured through the use of this system of drilling.

THE AMERICAN STANDARD CABLE DRILLING RIG

The usual arrangement of the various parts of the American standard cable drilling rig is represented in Fig. 28, page 115. Structural details of the derricks necessary in this as well as other systems of drilling are explained and illustrated on pages 126 to 142. We may broadly classify the remaining parts of the cable drilling rig under four headings. The power plant is customarily a single, horizontal-cylinder steam engine, though electric motors and internal-combustion engines are also used in cable drilling. The rig wheels, including the band wheel, the bull wheels, the calf wheel, sand reel and crown block, are important parts of the rig that warrant detailed description. The character of cables and cordage used for various purposes will be an important consideration. Lastly, the tools used in drilling by the cable method will be described in detail.

Power Plant for Cable Drilling

Most cable drillers prefer to use a steam engine as a source of power because of its superior flexibility. In most oil fields, too, there is an abundance of cheap fuel in the form of either natural gas or oil, so that steam power can be cheaply developed. The boiler plant is usually erected near the well so that it may be under the immediate control of the driller and his assistant, the "tool dresser," at all times. The tool dresser has occasional periods of freedom from operations in the rig, when he can give the boilers such attention as they require. Most cable drillers are familiar with steam equipment and are capable of making all necessary adjustments and replacements of engine and boiler parts.

For drilling with the American standard cable rig, it is customary to provide two boilers of from 30 to 70 rated horsepower, the actual power obtainable from them being somewhat greater than the rated horsepower. The return-tubular type of boiler, illustrated in Fig. 91, is probably the

most commonly used, though the locomotive type (Fig. 92), which requires but little in the way of masonry supports and is readily portable, is also popular. The latter style is occasionally mounted on wheels to facilitate transportation. Additional details concerning the several types of boilers used in supplying steam power for drilling purposes will be found in Chap. VII, pages 238 to 241. Working pressures of 100 to 175 lb. per square inch are usual. The steam consumption of a standard cable drilling rig, working at a depth of 2,800 ft. with 8-in. tools, ranges between 55 and 140 boiler hp., the latter figure being approached only occasionally for short periods of time in drawing out the tools. Drilling

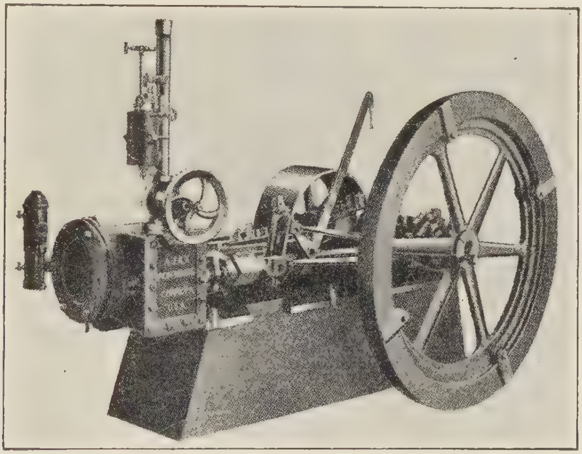


Fig. 38.—"Ajax" steam drilling engine.

on the beam consumes the minimum amount of power, and bailing operations require approximately 75 hp.

Steam engines used for cable drilling are usually of the simple, single-cylinder, reversible, slide-valve type of from 15 to 50 hp. Simplicity, flexibility and accessibility for repairs are matters of prime importance in the selection of an engine to meet the variable load requirements imposed. The type of engine generally used in cable-drilling practice has a cylinder 12 in. in diameter, a piston stroke of 12 in., and when operated under a steam pressure of 100 lb. per square inch develops about 30 hp. For lighter service in the drilling of shallow wells, an 11- by 12-in. (25-hp.) or even a 9- by 12-in. (15-hp.) engine may be used. Figure 38 illustrates a well-known oil-country engine of this type. Under the most favorable conditions the steam consumption of such engines, operating at full load with 100 to 125 lb. steam pressure, ranges from 30 to 40 lb. of steam per horsepower-hour. However, this figure may increase to as much as 100 lb. for average operating conditions.

The steam supply to the engine is regulated by a throttle controlled from the headache post by a telegraph cord and handwheel. A simple

reversing link on the eccentrics, operated by a lever and rod from the headache post, enables the driller to control the direction of rotation of the driving pulley. A heavy flywheel, to which additional weight in the form of extra balance rims may be clamped, serves to equalize the loads on the engine. Special lubricating devices, boiler feed-water pumps and heaters are often a part of the drilling equipment.

Electric motors have been successfully adapted to the work of cable drilling, though drillers are often reluctant to make use of electric power because of their greater familiarity with steam power.

For cable-drilling purposes, an ordinary variable speed, reversible, slip-ring induction motor with wound rotor gives best results. Speed control is effected through the introduction of a suitable resistance in the rotor circuit, adjusted by a controller. One successful type of drilling motor is equipped with an auxiliary controller in addition to the main controller, to give the finer speed adjustments necessary in adapting the movement of the walking beam to the period of vibration of the drilling cable. The main controller alone gives 10 points of speed control; the auxiliary controller cuts in 8 additional points between any adjacent points on the main controller. This gives 88 different speeds. The two controllers are located near the motor but are operated independently by telegraph cords from the headache post.

In cable drilling, the beam must overspeed on the down stroke, permitting a free drop of the drilling tools to strike the most effective blow. The motor therefore must slow down on the upstroke and overspeed on the downstroke. This is accomplished by introducing a secondary resistance in circuit when the motor is operated at proper speed.

An ammeter placed in the motor circuit is useful not only in indicating the power consumption during different phases of the work but serves also as an indication of the amount of strain placed upon the motor and derrick equipment. A recording ammeter is useful also as a check on the efficiency of the drilling crew and, to one skilled in interpreting the records obtained, provides an independent record of the operations in progress and the percentage of time devoted to different operations during each "tour."

For the standard sizes of cable-tool and rotary rigs, a 75-hp. drilling motor has sufficient capacity for the deepest wells now drilled. For shallower wells, say less than 2,000 ft. in depth, a 50-hp. motor is sufficient in many cases. In some foreign fields using other types of rigs, motors as large as 150 hp. have been used. Drilling motors can exert a very high pulling torque, and their ability to do so in an emergency is often important. The motor increases its pull automatically as the load increases, without any changes or adjustments, and develops its maximum pull at dead stall.

Wherever natural gas is available, the internal-combustion engine offers an economical solution of the power problem. In early efforts to adapt the gas engine to cable-drilling service, use was made of the horizontal, single-cylinder type of engine. This engine, however, was found to be poorly adapted to the requirements of drilling because of its lack of flexibility in speed and power output. The failure of this type of engine in operating drilling equipment seems to have prejudiced operators against all types of gas engines for this purpose, but tests recently made with vertical four-cylinder engines indicate that the larger sizes of multicylinder engines are capable of operating churn-drilling equipment in a satisfactory manner and at considerably less cost than is possible with the less efficient steam engine. The greater success of the multicylinder engine in comparison with the single-cylinder type is due primarily to its greater power and speed flexibility. Diesel engines, though adaptable to rotary drilling, are not suitable for cable drilling because of their lack of flexibility.

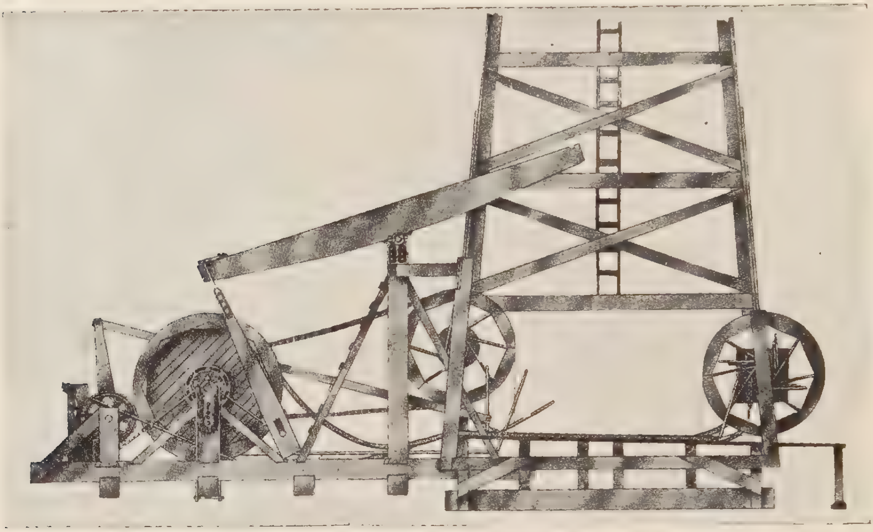
The type of internal-combustion engine that has been found most successful in operating cable-drilling equipment is modeled closely after the four-cylinder automobile engine, except that it is of higher power and is equipped with a special reversing drum and clutch, a flywheel and, sometimes, an auxiliary starting engine. The automotive type of gas engine, illustrated in Fig. 93, develops 120 hp. Constant speeds and power output can be maintained at from 85 to 500 r.p.m. It may operate on natural gas, gasoline or distillate. The chief advantage of the internal-combustion engine for drilling purposes lies in its economy. The gas engine requires about one-tenth of the fuel by weight that an oil-burning boiler requires and comparatively little water. It would appear to be particularly useful in drilling wildcat wells where fuel and water are large expense items.

The Rig Wheels

The large wheels which provide braking surfaces and a means of applying power in the various operations of hoisting and lowering the tools, casing and the bailer are usually built of wooden segments, cants and arms, rigidly nailed or bolted together. They are bolted to cast-iron gudgeons which provide a means of fastening them to the wooden or metal shafts on which they revolve.

The band wheel is a solid wooden wheel varying from 9 to 12 ft. in diameter, built of lumber segments held together by numerous bolts. The wheel has a smooth face, 12 in. wide, on which bear the belt from the engine pulley and the sand-reel friction pulley. The wheel is bolted at the center to two cast-iron hubs, one on either side, which provide a means of keying the wheel to the crank shaft on which it turns. Attached to one side of the band wheel is a wooden tug pulley 7 ft. in diameter, on

the rim of which one or two grooves are cut to receive the bull rope or ropes which drive the bull wheels. The steel crank shaft is supported



(*Courtesy of National Supply Co.*)

Fig. 39.—Side elevation of "standard" cable rig, showing sand reel, band wheel, crank, pittman, walking beam, calf and bull wheels and various rig posts and sills.

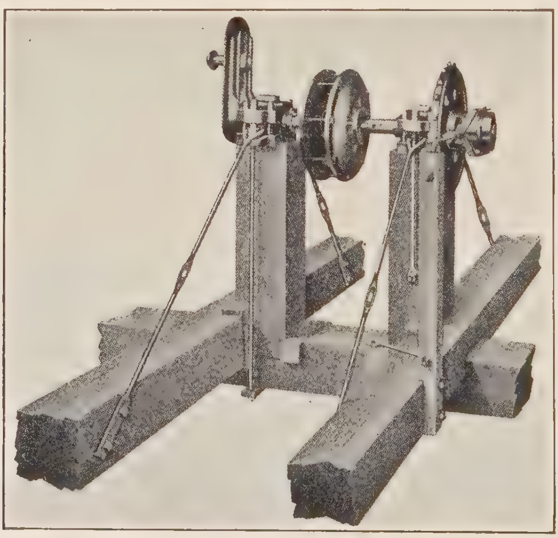


Fig. 40.—Showing assembly of crank, wrist pin, crank shaft, band wheel gudgeons, sprocket, clutch, braces and supporting posts and sills.

by two metal bearings, one on either side of the wheel, mounted on two upright jack posts (see Figs. 39 and 40).

The bull wheels, two in number, are mounted, one on each end of an oak shaft 14 or 15 ft. long and 16 or 18 in. in diameter. Sometimes a shaft of smaller diameter made of steel pipe is used. The wheels are 7½ or 8 ft. in diameter, built of oak cants and arms. The wheels are from 9 to 12 in. wide, one faced to a smooth braking surface for a metal band brake which bears upon it, and the other grooved to receive the drive from the bull rope or ropes. The bull-wheel shaft, when built of wood, is round in the center but is usually octagonal at the ends in order to provide a positive grip for the metal gudgeons which serve as the hubs of the wheels, to which the arms or spokes are bolted (see Fig. 41). The

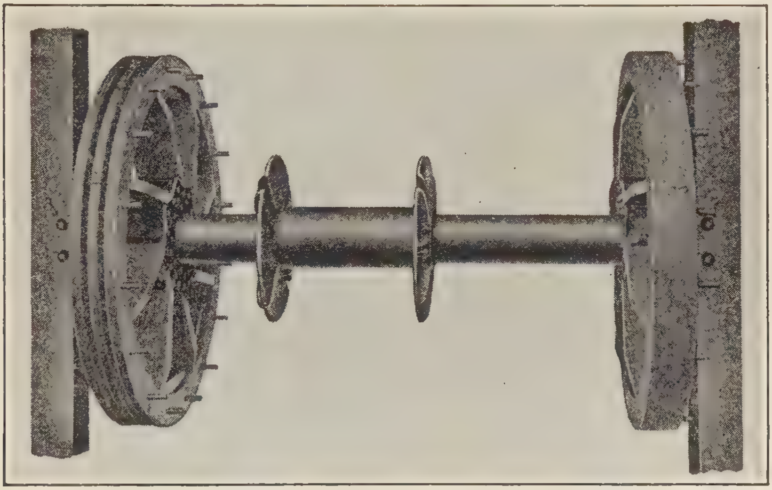


FIG. 41.—Bull wheels, showing shaft, spooling flanges and supporting posts.

metal gudgeons at the ends of the bull-wheel shaft are supported in metal boxes, mounted on substantial wooden "bull-wheel posts," braced between the derrick sills and the first horizontal girt. Around the side of each bull wheel 16 wooden handles are inserted. These are useful in turning the wheels by hand when necessary in taking up slack in the drilling cable. Mounted on the bull-wheel shaft are two adjustable "spooling flanges" which prevent the drilling cable from slipping on the shaft and confine the portion of the cable in actual use to the central section.

The calf wheel is usually built more substantially than the bull wheels because of the greater strain to which it is subjected, but it is similarly constructed of oak cants and arms. Heavy calf wheels have twice as many arms as the ordinary bull wheel, the arms being braced in pairs in opposite directions (see Fig. 42). The calf-wheel shaft is similar in its construction and equipment to the bull-wheel shaft described in the preceding paragraph, except that it is shorter. It is supported by

a pair of heavy upright posts and turns on steel gudgeons resting in metal boxes. Mounted on one side of the calf-wheel rim is the sprocket wheel which receives the chain drive from the crank-shaft sprocket. An earlier type of calf wheel using a rope drive instead of the chain drive is now almost obsolete. Frequently, the steel surface of the calf-wheel shaft is lagged with hemp rope to prevent abrasion of the casing line wound on it. A steel band brake operated by a lever bears on the wooden face of the calf wheel and prevents it from turning when it is required to support heavy loads.

The sand reel is an all-metal drum, keyed to a steel shaft to which is also attached a cast-iron friction pulley (see Fig. 39). The sand line is

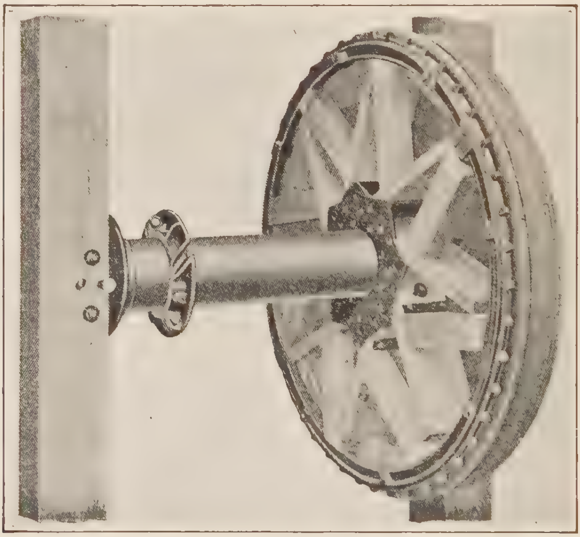


Fig. 42.—Calf wheel, showing shaft, sprocket and supporting posts.

wound on the drum. The friction pulley may be brought to bear against the face of the band wheel, causing the sand-reel shaft and drum to revolve. The drum is usually about 3 ft. long and varies from 6 to 20 in. in diameter. The drum flanges are often about 3 ft., and the friction pulley about 40 in. in diameter. The sand-reel shaft is supported by metal bearings mounted on a movable timberframe pivoted at its lower end on two heavy "sand-reel posts." This frame may be drawn forward by the "sand-reel lever" until the friction pulley bears against the revolving band wheel, or it may be forced backward against a wooden post which bears against the friction pulley, serving as a brake to control the descent of the bailer. An improved type of sand reel is driven by a chain from a sprocket on the crank shaft. A chain-driven sand reel provides a more positive power connection for operation of the bailer, which is especially desirable in deep-drilling operations where the loads to be handled are often excessive for the friction type of drive.

The crown block contains 6 or 7 cast-iron pulleys ranging from 24 to 36 in. in diameter, supported by metal boxes, bolted to substantial oak or steel supports (see Fig. 43). These sheaves should be of large diameter in order to avoid sharp bends in the cables passing over them. The largest sheave, usually 36 in. in diameter, is the "crown pulley," over which the drilling cable passes. The "sand-line pulley" is of intermediate size, often 30 in. in diameter. The four (sometimes five) smaller sheaves are provided for the support of the casing line, which is threaded back and forth between them and the sheaves in the hoisting block. The number of sheaves provided for the casing line depends upon the load likely to be imposed, the mechanical advantage in favor of the power being in

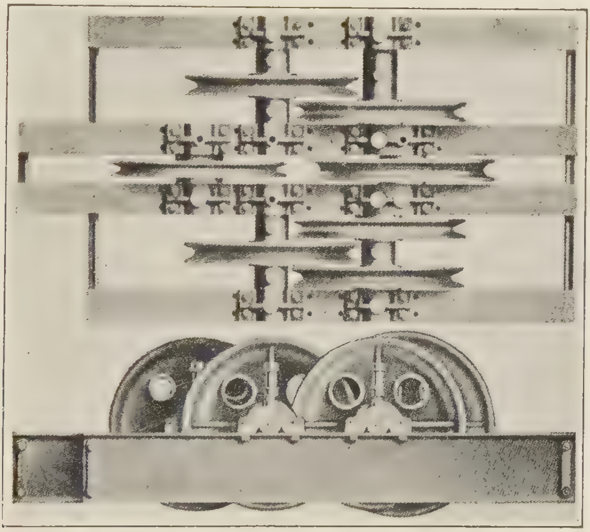


FIG. 43.—Seven-sheave crown block for combination rig.

direct ratio to the number of ropes extending between the crown block and the hoisting block.

The Rig Irons.—All of the metal parts used in the construction of the standard cable rig, with the exception of the nails, bolts, sand reel and guy wires, are known collectively as the "rig irons." They include such items as the gudgeons, shafts and boxes of the wheels, the crank and wrist pin, the sprocket wheels chain and clutch, a metal stirrup for the pittman, the center irons or metal bearing on which the walking beam oscillates, together with numerous bolts and fastenings. Rig irons are furnished in complete sets by the manufacturers, varying in size and weight with the size of the rig for which they are intended. The size is designated by the diameter of the crank shaft, which may vary from 4 to 7½ in. Rig irons of the 4- and 5-in. sizes are used only for shallow wells and light work, the 6-in. size being commonly employed for heavier duty. Aside from differences in size and weight, there is some variation in design

of rig irons and in the list of parts furnished in sets. Thus, the California pattern, Oklahoma pattern and Pennsylvania pattern rig irons differ from each other in certain respects, being designed particularly for the type of rigs favored in the regions after which they are named.

The American Petroleum Institute has recently adopted standard specifications for rig irons in which working dimensions for all parts are prescribed. This is designed to facilitate interchangeability of parts and will permit of the products of one manufacturer being used in the same rig with those of another.

Cables and Cordage

The selection of material for the cables and ropes used in driving the wheels, operating the drilling tools and bailer and supporting the casing must receive careful attention. Both hemp and manila sisal and steel wire are used in the construction of these cables, and special forms have been devised to adapt them better to the purposes for which they are used.

The Drilling Cable.—Probably the most important of the cables used in the standard rig is the drilling cable which serves to connect the drilling tools in the well with the power at the surface. When drilling is in progress, the drilling cable is suspended from the walking beam to which it is attached by the temper screw. The surplus cable is carried up through the derrick over the large central crown pulley and thence down to the bull-wheel shaft on which it is coiled. When the drilling tools are being lowered or hoisted, or are suspended in the derrick, the tension in the drilling cable is transferred directly to the bull wheels and crown pulley.

The duty imposed on the drilling cable is severe. Not only must it support the weight of the tools (often between 1 and 2 tons), but the dead weight of the cable itself may be as great as that of the tools when operating at a depth of 2,000 or 3,000 ft. Furthermore, the strain imposed by the alternate application and relief of tension with each stroke of the tools, and the wear resulting from rubbing of the outer strands of the cable on the rough rock walls of the well and the metal casing, tend to weaken it and to shorten its useful life.

Hemp Drilling Cables.—Both manila fiber and steel wire have been widely used in the construction of drilling cables, but the former is generally preferred where its strength is adequate on account of its greater elasticity. With proper adjustment of the temper screw and motion of the walking beam, a much harder blow may be struck with the tools when they are suspended on a hemp cable than is possible with steel, because of the greater elasticity of the hemp cable, which materially increases the length of stroke. Furthermore, if the temper screw is adjusted so that the tools strike bottom on the "spring" of the line, they rebound quickly when the blow has been struck, thus dislodging the bit from the cuttings which otherwise tend to hold it. The hemp cable imposes less strain on the derrick and makes hole faster than does the steel cable.

Hemp cables of 2, $2\frac{1}{4}$ and $2\frac{1}{2}$ in. diameter have been widely used in the drilling of wells up to 1,500 or 2,000 ft. in depth, but at greater depths the large-sized cable necessary becomes expensive and impracticable and a steel cable must be substituted. During drilling operations the well must be at least partially filled with water, and the friction developed by the motion of a rough manila cable of large diameter, through this water, seriously reduces the force of the blow struck by the tools and increases the power consumption. The displacement of fluid in the well by so large a cable is also excessive in a hole of even moderate diameter, so that the tools do not drop promptly on the downstroke of the walking beam, as they should for best results.

Manila drilling cables are made of a selected grade of manila hemp in long fibers, twisted especially hard to withstand the severe strain to which they are subjected.

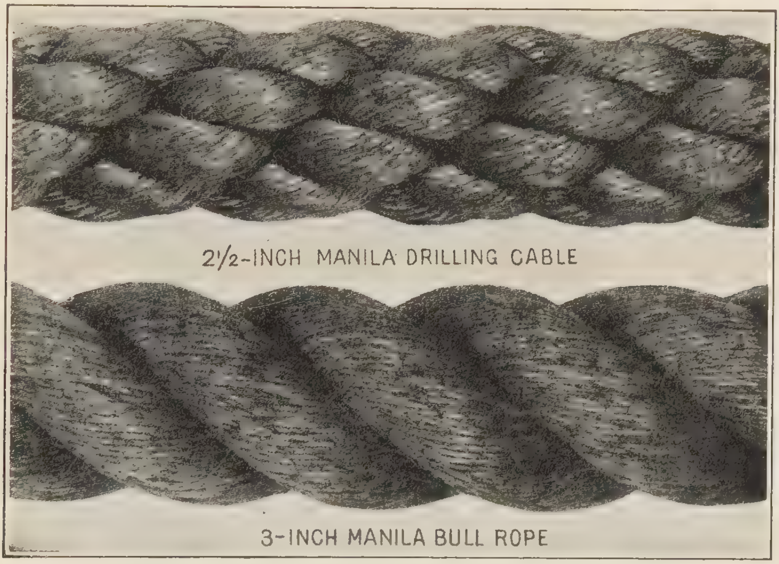


Fig. 44.—Types of cordage used in cable drilling rigs.

The fibers composing the strands are given a left "lay" or twist, while the strands making up the ropes are given a right lay. The three ropes composing the cable are tightly twisted in the reverse direction to the twist of the cable itself in order to prevent the cable from kinking readily and so that the cable will not unwind when subjected to heavy loads. This construction (see Fig. 44) results in the individual strands running parallel with the axis of the rope and there is less abrasion of the outer strands than would be the case if they assumed an angular position. To achieve an equal distribution of the load on the three ropes composing the cable, the lay of the strands, ropes and cable must be perfectly uniform throughout.

The strength of a hemp cable depends directly upon the strength of the individual fibers and the means adopted for preventing them from pulling apart. They may fail either through breakage of the fibers or by the pulling apart of the several fibers which make up the strand. Since the original fibers will seldom be more than 3 ft. long, and often a good deal less than this, it is evident that the strand depends for its strength upon the friction developed between the individual fibers by twisting. If a strain is put upon the rope in excess of the frictional resistance to movement of the fibers, they pull apart or slide on each other. Wetting the hemp fibers will decrease their coefficient of friction. It is found that a hemp cable properly designed to develop

the proper amount of friction to prevent it from pulling apart when dry, may lose as much as 30 per cent of its strength when wet. This of course has no bearing on the failure of the rope by direct breakage of the fibers.

The weight and strength of hemp cables of this type will vary somewhat with the quality and condition of the fiber and the care taken in their construction. Table XV presents what are considered by a large rope manufacturing company to be average figures for the commonly used sizes of drilling cables. Hemp drilling cables

Table XV.—Weights, Sizes and Strengths of Manila Drilling Cables*

Diameter, in.	Circumference, in.	Pounds per foot	Ultimate strength of new rope, lb.
1½	4½	.949	17,000
1¾	5¼	1.280	25,000
2	6	1.580	30,000
2¼	7	1.790	37,000
2½	7½	2.330	43,000

* Data furnished by Tubbs Cordage Company of San Francisco, Calif.

usually stretch about 50 per cent of their original length during continued use so that a 1,500-ft. cable will often serve for the drilling of a 2,000-ft. hole. Hemp and manila rope deteriorate rapidly in dry climates, becoming dry and brittle and losing much of their strength and pliability. When not in use, hemp cable should be stored in a cool and moist place. Storehouses carrying a considerable stock of hemp or manila cordage should be equipped with a humidor for its preservation during the period of storage.

Steel Drilling Cables.—The elasticity of the hemp cable is to a large extent lacking in the steel cable until the length reaches 1,000 ft. or more, and in some regions

(American Steel and Wire Co., New York.)
Fig. 45.—Steel wire drilling cable, 6 by 19.

it is customary to use the steel cable only after this depth has been attained with a hemp cable. While something is undoubtedly sacrificed in the use of the steel cable through its lower elasticity, there are certain compensating advantages which often make its use preferable. For example, in drilling with a high fluid level in the well, the smaller diameter of the steel cable results in less displacement of water, and because of its relatively smooth outer surface it moves through the fluid with less friction. Furthermore, it is stronger, has a longer life and for deep wells is cheaper.

In order to secure the maximum of pliability, the steel cable is made of a large number of wires, usually 114, assembled in six strands of 19 wires each, and twisted around a hemp core which provides a cushion for the wire strands and prevents them from abrading each other (see Fig. 45). For light service, a rope constructed of six strands of seven wires each is sometimes used. The steel of which the wires are composed is preferably a high-grade crucible steel or plow steel, commonly used in hoisting

cables subjected to severe abrasion. Table XVI gives the sizes, weights and ultimate strengths of steel cables of this type. For light work and in holes of small diameter, ¾-in. steel cables are commonly used, but, for heavy service, cables ranging in diameter from ⅞ to 1½ in. are customary.

In determining the allowable working strain on a steel cable used in oil-well service, it is customary to adopt a safety factor of five; that is, the cable used should have a breaking strength approximately five times the estimated working load. This latter quantity, however, cannot be determined precisely, inasmuch as it is influenced by many conditions the effect of which can only be estimated. Probably every cable employed in oil-well service is at times subjected to tensile stresses approaching its breaking strength, and, since the elastic limit of steel is only about 60 per cent of the breaking strength, the character of the steel will be materially altered and the useful life of the cable shortened by overstrain.

Table XVI.—Weights, Sizes and Strengths of Steel Drilling Cables and Casing Lines*

Diameter, in.	Circumference, in.	Approximate weight per foot, lb.	Approximate strength, tons of 2,000 lb.	Maximum working load, tons of 2,000 lb.	Diameter of drum or sheave advised, ft.
Crucible steel, extra strong, 6 by 7 wire cable					
1½	4¾	3.55	73.00	14.60	11
1⅜	4¼	3.00	63.00	12.60	10
1¼	4	2.45	54.00	10.80	9
1⅛	3½	2.00	43.00	8.60	8
1	3	1.58	35.00	7.00	7
⅞	2¾	1.20	28.00	5.60	6
¾	2¼	.89	21.00	4.20	5
11/16	2⅛	.75	16.70	3.30	4¾
⅝	2	.62	14.50	2.90	4½
9/16	1¾	.50	11.00	2.20	4
½	1½	.39	8.85	1.80	3½
7/16	1¼	.30	6.25	1.25	3
⅜	1⅛	.22	5.25	1.05	2¾
Crucible steel, extra strong, 6 by 19 wire cable					
1½	4¾	3.55	73.0	14.60	6.0
1⅜	4¼	3.00	64.0	12.80	5.5
1¼	4	2.45	53.0	10.60	5.0
1⅛	3½	2.00	43.0	8.60	4.5
1	3	1.58	34.0	6.80	4.0
⅞	2¾	1.20	26.0	5.20	3.5
¾	2¼	.89	20.2	4.04	3.0
⅝	2	.62	14.0	2.80	2.5

* As manufactured by the American Steel and Wire Co.

Care should be taken in selecting the size of sheaves over which the steel cable is passed or the size of drums or shafts on which it is wound to have the diameter of the sheave not less than about 30 or 40 times the diameter of the cable and preferably

larger. In handling the cable, care should also be taken to avoid sharp bends or kinks which may permanently alter the alignment of the strands and wires, weakening the cable and subjecting it to abnormal abrasion.

It is often necessary to splice wire cable in adding a new length or in replacing a worn section. The "blind splice" is generally used. The strands of each of the two ends are unwound for about 15 ft., the hemp core extracted and the strands of the two ends woven together, one of the strands taking the place of the core. For drilling cables used in very deep wells, it is sometimes desirable to use a larger size of cable on the upper end than on the lower, thus making allowance for the considerable dead load of the cable as greater depths are attained. For example, in the drilling of a 7,500-ft. well in West Virginia the drilling cable used consisted of sections of 1½-, 1⅛-, 1- and ⅞-in. cables with specially built tapered joints about 150 ft. in length.

The life of steel drilling cable is extremely variable and depends to a large extent on the hardness of the formations penetrated and the care with which it is handled. In some cases a cable may be worn out in the drilling of a single well. In drilling the 7,500-ft. well mentioned in the previous paragraph, ten 8,000-ft. drilling cables and three $\frac{9}{16}$-in. sand lines were used. In order to secure in some measure the advantage of the more elastic hemp cable, some drillers fasten about 100 ft. of hemp cable on the lower end of the steel cable. This "cracker line," or "snapper line," so called, has in addition the advantage of the small diameter and low cost of the steel cable. It is chiefly used in the oil fields of Illinois, its use in western drilling practice being uncommon.

The Casing Line (or **"Calf Line"**).—While the calf line is not subjected to the destructive jar and rapid variation in intensity of strain that are characteristic of drilling operations, the load to be sustained by it is occasionally greater than that imposed on any other cable in the rig. The dead weight of a long column of heavy casing suspended on this cable is alone sufficient to place it under considerable tension, and since this may be exceeded by the frictional resistance of the "formation" in lifting the casing, it is apparent that at times the material will be stressed to a degree that will exceed its elastic limit.

The casing line, it will be recalled from the foregoing general description of the rig, is coiled on the shaft of the calf wheel, the free end being carried over the crown block and threaded back and forth between two or more casing pulleys and the sheaves of the hoisting block. The end of the cable, or dead line, is attached either to the bail of the hoisting block or to the derrick sills. The number of lines strung between the derrick crown and the hoisting block determines the tension in the line that is developed during the lifting of a given load. The actual strain may be computed by dividing the weight of the load to be lifted by the number of lines.

The casing line is usually constructed of steel wire, being designed particularly to withstand severe tensional strain. It must be pliable in order that it may bend to the rather small diameter of the sheaves over which it passes without abnormal bending stresses. The construction is quite similar to that of the steel drilling cables described above, the cable

built of six strands of 19 wires each, with a hemp core, being a common type. Diameters ranging from $\frac{3}{4}$ to 1 in. are customary (see Table XVI). The material may be softer, however, since the outer strands are not particularly subjected to abrasion, which is an important factor to consider in the selection of a drilling cable. For the drilling of very shallow wells, or in regions where only light casings are used, the casing line may be of hemp instead of steel. In such cases the calf wheel may be omitted in the equipment of the rig and the casing line coiled on a part of the bull-wheel shaft, or the drilling cable may be detached from the tools and used for handling casing.

The Sand Line.—The strain which the sand line will be required to sustain is comparatively small, since the dead load of the bailer and its contents seldom exceeds 2 tons even in the larger sizes of bailers. It is, however, subjected to considerable abrasion, as a result of contact with the walls of the well and casing during operation of the bailer. In addition, it must be sufficiently pliable to bend freely over the sand pulley at the crown block and to wind without abnormal strain on the drum of the sand reel.

For service of this character a steel wire cable composed of six strands of seven wires each, wound on a hemp core (see Table XVI) has been found satisfactory. Diameters range from $\frac{3}{8}$ to $\frac{5}{8}$ in., the $\frac{1}{2}$-, $\frac{9}{16}$-, and $\frac{5}{8}$-in. sizes being commonly used. The smaller sizes are appropriate only in shallow wells. Manila sand lines ranging in diameter from $\frac{5}{8}$ to $1\frac{1}{4}$ in. are occasionally used in shallow wells, but their life is short because of the continual surface abrasion and alternate wetting and drying to which they are subjected.

Guy Wires.—For guying derricks it is customary to use a galvanized wire strand composed of seven wires twisted into a single strand. Available diameters range from $\frac{5}{64}$ to $\frac{5}{8}$ in.

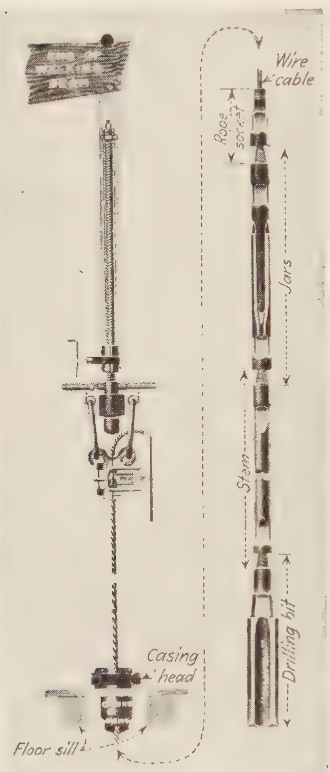
Bull Ropes.—The rope drive connecting the tug pulley on the band wheel with the rim of the left-hand bull wheel consists of one or two endless hemp or manila ropes, 2 or 3 in. in diameter, built of a large number of small strands loosely twisted together, forming a strong and exceptionally pliable rope (see Fig. 44). The bull ropes are frequently thrown from their grooves during the manipulation of the tools by the side thrust of a wooden lever mounted near the bull wheels. The ropes are crossed between the tug pulley and the bull wheels in order to reverse the direction of the power, and, except for the rubbing of the ropes on each other where they cross, and occasional slippage in the grooves in which they run, there is little abrasion. The life of the bull rope is influenced chiefly by the strain put upon it, resulting in direct breakage of the strands and pulling apart of the fibers.

Other cordage used in the derrick is of minor importance, consisting for the most part of hemp rope or light steel-wire strand used in support-

ing the heavy casing tongs, connecting the temper screw with its counterbalance, connecting the "telegraph wheel" with the engine throttle and like purposes.

String of Cable Drilling Tools

The string of cable drilling tools consists of several parts (see Fig. 46), securely fastened together by tapered screw ("pin") joints. The rope socket which connects the tools with the drilling cable is screwed to the top of a pair of massive telescoping metal links called "jars." These in turn connect at their lower end with a long cylindrical steel "drill stem," and the latter is screwed to the top of the drilling bit. Occasionally a "sinker bar," a short cylindrical steel bar, is inserted between the top link of the jars and the rope socket. The total length of the string of cable tools so connected is usually about 40 ft. The aggregate weight depends upon the size of hole to be drilled and for a 10-in. hole averages about 3,600 lb.



(*Courtesy of Oil Well Supply Co.*)

Fig. 46.—The "string" of cable drilling tools showing, at left, the drilling cable suspended from the end of the walking beam by the temper screw; at right, the assembled string of tools that enters the well.

Cable drilling bits are of several types differing slightly from each other in form and purpose (see Fig. 47). The bit is made of a heavy bar of steel or iron, from 4 to 11 ft. long (commonly 7 or 8 ft.) and somewhat wider than it is thick. It is dressed to a blunt edge on one end and terminates in a tapered "tool joint" at the other. The upper shank of the bit, which is somewhat smaller than the cutting edge, is flattened just below the joint to facilitate the application of a wrench in screwing it to the drill stem. A wide groove or "water course" is cut down each side of the tool to permit of the easy displacement of the fluid in the well as the tools rise and fall.

The form of the cutting edge is varied to adapt it to the character of the rock formation to be drilled. For hard rocks, a fairly sharp chisel edge is used, while for soft material the bit will be almost flat on the bottom with only a blunt edge at the center. A chisel-edged bit operating in soft rocks will loosen the material faster than it can be mixed with water, so that the bit rapidly becomes clogged. In "dressing" the bits,

particular attention is given to shape the edges and corners properly, since the size of the hole drilled and the "clearance" of the bit in the hole depend largely upon these details. For soft rocks the cutting edge will be dished in somewhat toward the center so that the corners project slightly. In hard rocks the cutting edge should be almost a straight line, in order to distribute the wear on the bit uniformly and to prevent breakage of the corners.

Several common types of cable-tool bits are illustrated in Fig. 47. The California pattern represents a widely used type, though the Mother Hubbard pattern is preferred by many drillers, particularly in north Texas, on account of its angular form, which, it is claimed, results in

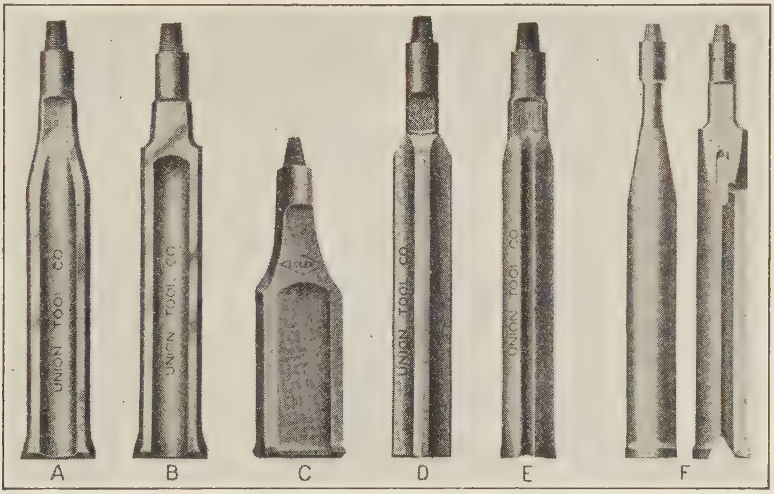


Fig. 47.—Types of churn drilling bits.

A, California pattern; *B*, Mother Hubbard pattern; *C*, spudding bit; *D*, star bit; *E*, round reamer; *F*, Overman bit.

the drilling of a straighter hole. The spudding bit is a short, broad form used only in starting the well. The star bit and reaming bits are used for straightening a crooked hole and enlarging the diameter from the top down. In another style, the spiral bit, the blade is twisted about the vertical axis of the tool so that the edges and water courses assume a spiral appearance. The shank of the bit is usually made several inches smaller in diameter than the cutting edge, which permits the bit to work in the hole eccentrically thus drilling a hole somewhat larger than the actual gage of the bit.

Drilling bits are preferably made of a good grade of tool steel which may be accurately tempered to the proper degree of hardness and which holds its cutting edge and resists abrasion. Chrome and other special steels are occasionally used. To reduce the cost, some manufacturers use tool steel only on the lower one-third of the bit, the shank and upper end being composed of a cheaper grade of forged iron or mild steel. This

practice is permissible if the weld connecting the two metals can be satisfactorily made. The bits are seldom dressed back in resharpening to more than one-third of their original length before they are discarded or a new piece of steel is welded on. The metal comprising the upper part of the bit is useful only in adding weight.

Too little attention is given to the proper tempering of drilling bits for best results. The hardness of the rocks to be penetrated should always be considered in tempering the steel. The work of sharpening and tempering the bits is often entrusted to the driller and his tool dresser, who are frequently not sufficiently skilled in the art of tempering and heat treatment of steel for best results. Furthermore, the equipment provided at the rig for this work is often inadequate. A better practice would seem to be to send the tools to a well-equipped forge shop where they may receive the attention of a skilled tool sharpener.

Difficulty is experienced, especially with the larger sizes of bits, in cracking or breaking of the metal, particularly at the corners and through the thinner metal separating the water courses. This is usually a result either of uneven heating or of using too hard a temper. Large bits should be heated in a very slow fire and frequently turned, special care being taken to avoid overheating of the corners, edges and thinner portions. The metal should be tempered to a straw color on the cutting edge, plunged and allowed to cool slowly with the cutting edge immersed in 1 in. of water or mud. Bits dressed with an uneven cutting edge frequently break at the pins or in some cases at the wrench squares.

The tool joints, used in connecting the several parts of the string of cable drilling tools, are equipped with taper-screw threads in order to facilitate coupling and uncoupling of the parts (see Fig. 48). They are made of soft annealed steel and are provided with shoulders about 1 in. wide between the threads and the outer circumference of the box. When the shoulders on the two parts of the joint butt together, the friction developed prevents unscrewing as a result of vibration in the well. When the joints are in good condition they can be screwed by hand until they come within about 1/16 in. of shouldering, after which a wrench operated by a powerful circle jack bolted to the derrick floor must be applied (see Figs. 49 and 50). When the joints are new they should be set up by the jack and unscrewed several times before being put into use. They should always be thoroughly clean, free from grease and rust, and the shoulders should be smooth so that they butt properly together. When the threads become cupped as a result of excessive strain put upon them, they should be sent to the shop for rethreading.

For the larger sizes of tools the joints are usually 4 in. in diameter at the base and taper to 3 in. at the top. They are cut with seven threads to the inch, and are known as "3 by 4 in.–7 joints." The threads may be sharp 60 deg.-V threads or they may be flattened as in the U. S. Stand-

ard thread. The outer diameter of the metal "box" is usually 6 in. Other commonly used sizes of tool joints are 4 by 5 in.–7, 2¾ by 3¾ in.–7, 2 by 3 in.–7 and 1¾ by 2¾ in.–8. The size of the pins must be proportioned to the size and weight of the tools, otherwise the string of tools is apt to pull apart at a tool joint ("jump a pin") during operation in the

Fig. 48.—Detail of tool joint.

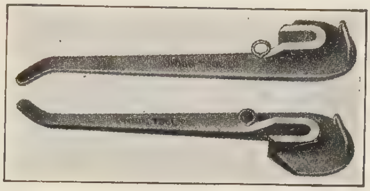


Fig. 49.—Tool wrenches.

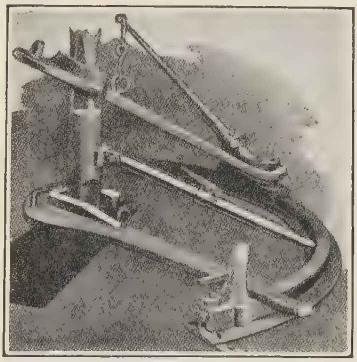


Fig. 50.—Circle jack in position for setting up tool joint.

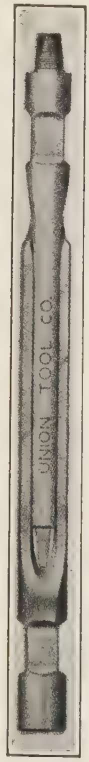


Fig. 51.—Drilling jars.

well. For heavy work in north central Texas it is customary to use a 5½-in. by 30-ft. auger stem equipped with a 4- by 5-in. box and a 3¼- by 4¼-in. pin. The drilling jars used are 6½ in. and are equipped with a 3¼-by 4¼-in. box and pin. The American Petroleum Institute has standardized tool joints, so that the equipment of different manufacturers may be used in making up a string of tools.

The drill stem, or auger stem as it is occasionally called, is a cylindrical bar of mild steel or iron equipped with a tool joint and wrench squares at either end. The function of the stem is merely to add weight to the drilling bit. The size varies with the diameter of the hole to be drilled, ranging from 2½ to 6 in. in diameter and from 6 to 42 ft. in length. A spiral form of drill stem, supposed to give the tools a rotating motion as they rise and fall through the well fluid, is preferred by some drillers.

The drilling jars resemble two great links of a chain and are carefully made to slide on each other or telescope (see Fig. 51). The two links are of massive construction, reinforced at the ends where they engage each

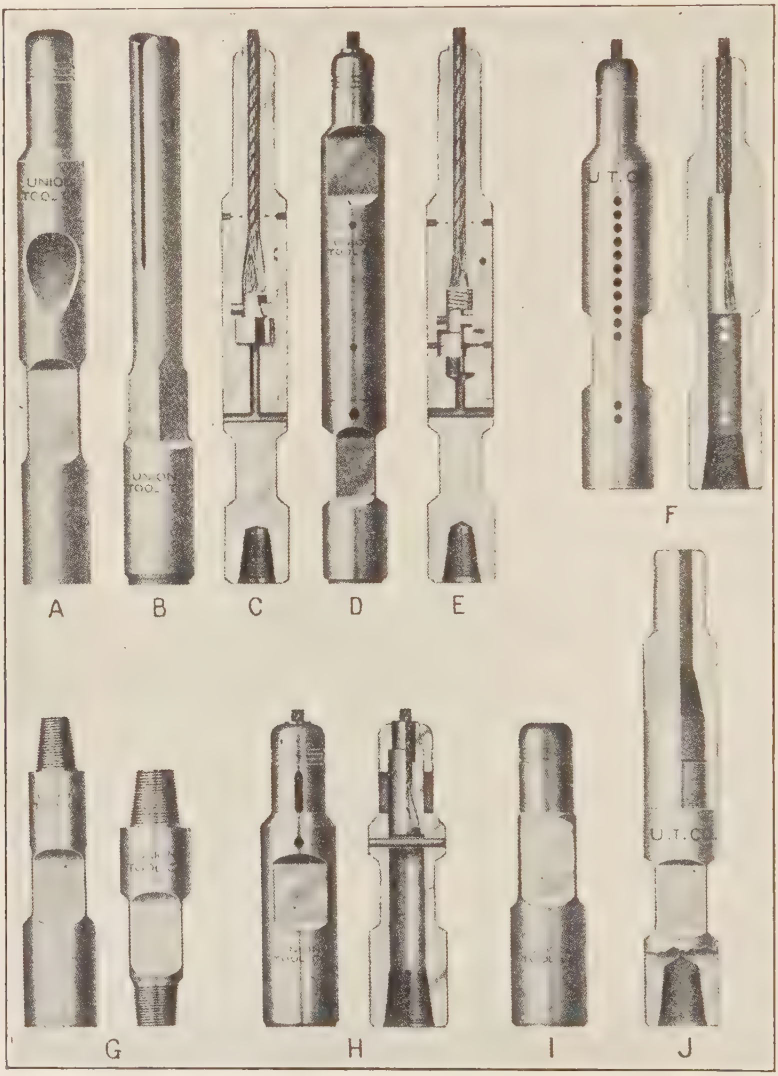


Fig. 52.—Types of rope sockets.

A, New Era socket; *B*, wing socket; *D*, Union rope socket; *C*, ratchet type; *E*, roller-ratchet type; *F*, Prosser socket; *G*, types of substitutes; *H*, double-swivel socket; *I*, Babcock socket; *J*, Babcock manila-rope socket.

other and provided with tool joints at the outer ends. They are of such length that they may telescope for a distance of about 16 in., though "fishing jars" of similar design may have a stroke of as much as 36 in.

The purpose of the jars is to enable the driller to strike a sharp upward blow on the drilling bit, which is frequently necessary in freeing it from

clay or shale in which it tends to stick. By adjusting the stroke and the position of the tools in the well, the jars may be allowed to telescope for from 6 to 12 in. on each downstroke. On the upstroke the upper link gathers momentum before it engages the lower, and the tools are suddenly jerked from the sticky material which tends to hold them. In other cases the bit may become wedged in the hole, or caving of the walls may necessitate the application of a succession of upward blows before the tools can be freed. The jars are often able to loosen the tools when a direct pull on the drilling cable would be quite ineffective. The jars are not brought into play or can be omitted from the string of tools when drilling in hard rocks.

The sinker bar is similar to the drill stem in form, except that it is shorter. It is used merely to add mass to the weight of the upper link of the jars, thus making the latter more effective in freeing the tools on the upstroke.

The rope socket, which serves to connect the string of tools with the drilling cable, may be one of several types. Those intended for use with hemp cable necessarily differ in form from those used on steel wire cable. The form of the socket should be such that the cable is not subjected to any sharp bends on which it is likely to break, and it should provide a positive grip, strong enough to resist any pull short of that necessary to break the cable. In addition it must be substantial to withstand the wear and abrasion to which it is subjected, and it should provide a means of conveniently connecting with the drilling tools.

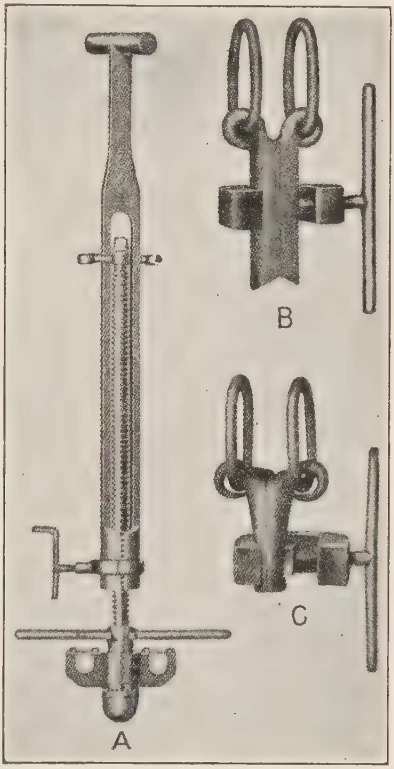


FIG. 53.—Temper screw (*A*) with drilling cable clamps for steel wire cable (*B*) and for manila cable (*C*).

For hemp drilling cables, the New Era socket and the wing socket with rivet fastenings have been widely used (see Fig. 52). In the case of wire rope the strands are usually unwound or loosened slightly at the ends and babbitted in a conical recess provided in the socket. The Babcock socket is the best known example of this type. In the Prosser socket the cable is held by a pair of cone-shaped slips with serrate teeth, which grip it securely when they are drawn up into position. Some drillers consider

it an advantage to be able to rotate the drilling tools, with the thought that this procedure prevents them from striking repeatedly in the same place thus avoiding a "flat" hole. While the necessity for this rotation of the tools is doubtful since they naturally turn in the hole as the tension in the long cable is alternately applied and released, some manufacturers have catered to this whim of the driller in the design of ratchet rope sockets which permit of the lower half of the socket turning with respect to the upper half. The Union roller-ratchet socket is an example of this type.

A variety of forms of "substitutes" for connecting the rope socket with tubing or with the many types of fishing tools are available, as well as rope clamps, clips and thimbles used in forming and supporting loops made in the end of a cable.

The temper screw is the device by means of which the drilling cable and tools are suspended from the walking beam, and with the aid of which the tools are gradually lowered so that they continue to strike the bottom of the hole as it is deepened. Figure 53 shows that it consists of several parts. A substantial metal frame, suspended by a T-bar at its upper end from a slot in the "nose" of the walking beam overhanging the well, supports a split nut between the two reins at the bottom. The two halves of this nut spring slightly apart with the reins in their normal position, but by means of a small elliptical clamp they can be brought together so that their threads engage those of the screw. The screw is from 5 to 8 ft. in length, 2 in. in diameter and cut with a coarse square thread. Attached to the lower end of the screw is a handle by means of which it can be revolved, and a pair of links supporting a clamp which grips the drilling cable. The links pass through holes in a short metal crossbar or swivel, resting on a shoulder cut on the end of the screw. Frequently, cone or ball bearings will be placed between the crossbar and the supporting shoulder so that the screw may be revolved freely without turning the links or rope clamps.

The form of the rope clamps will vary with the kind of drilling cable used. They must be of such shape that they will not damage the drilling cable, and yet they must apply sufficient pressure to prevent it from slipping through. When a manila drilling cable is used, it is customary to wrap loose strands of old rope about it at the point where it is gripped by the metal clamps. This additional material is so adjusted that it forms a wedge in the upper part of the conical opening in the clamp. For steel drilling cables the clamps consist of two bars of steel with grooves cut through the center to fit the size of the cable being used.

By turning the handle in the lower end of the screw, the latter can be advanced through the split nut until the full length of the screw has passed through. In order to take a new grip on the cable so that drilling can be continued, the weight of the drilling cable and tools must be trans-

ferred from the beam to the crown block and the temper screw loosened on the cable. By loosening the clamp which holds the two halves of the split nut together, the reins spring apart, releasing the nut from the screw which can then be lifted to the top of the frame. The two halves of the nut are then again clamped about the screw, the lower clamps are attached to the drilling cable, the weight of the tools is transferred back to the beam and drilling is resumed.

The weight of the temper screw and all its parts will vary from 300 to 500 lb., depending upon the length of the screw and the depth of well for which it is intended to serve. To aid in lifting the screw in the frame, it is usual to attach to its upper end a rope which passes up over the top of the beam and thence down to a balance weight at the side of the Samson post.

The circle jack, by means of which the several parts forming the string of cable tools are screwed together, consists of a semicircular toothed rack which is fastened to the derrick floor around the mouth of the well (see Fig. 50). At one end of the toothed rack a large wrench is held in a stationary position. A second wrench is attached to a traveler containing a ratchet operating on the toothed rack. As the handle is moved backward and forward, the ratchet moves forward one tooth on the rack for each stroke of the handle, thus advancing the movable wrench. In applying the circle jack the tool forming the lower portion of the tool joint is lowered into the well until the wrench square is just level with the derrick floor and is gripped by the stationary wrench. The wrench square on the upper portion of the joint is then gripped by the movable wrench and the traveler is advanced on the rack until the joint is tight. The joints are generally screwed together as far as is possible by hand, before being lowered into the well and tightened by the circle jack.

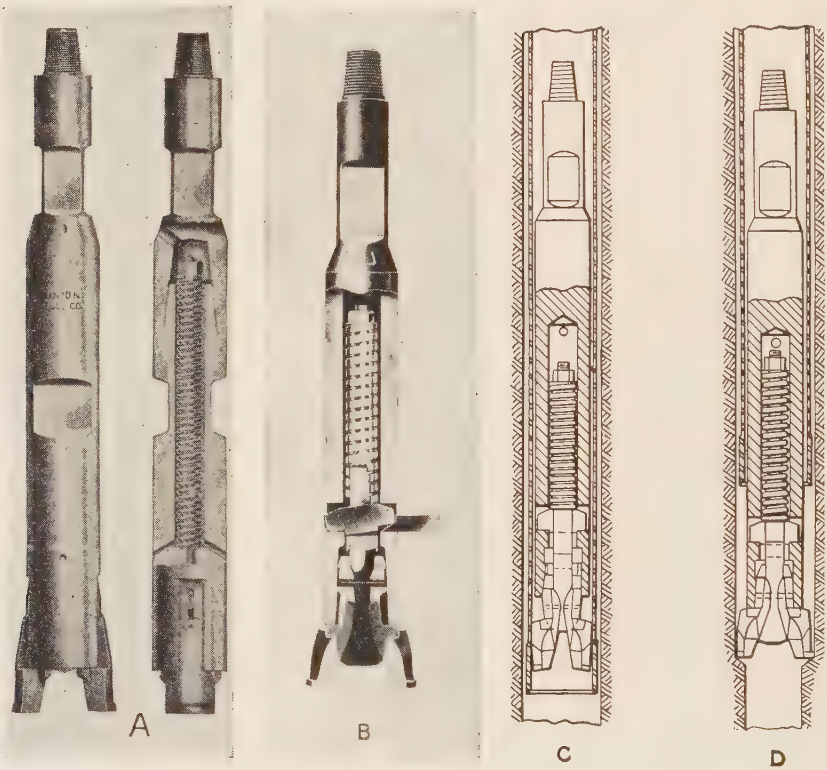
Under-reamers.—It frequently happens, especially in drilling through hard rocks, that the drilling tools do not maintain sufficient clearance to permit of free passage of the casing. In such a case an under-reamer may be lowered to the tight place and manipulated in such a way as to enlarge that particular section to the necessary diameter. Under-reamers also find application in reaming out holes at points where free space about the casing is desired for the introduction of cement in excluding water.

A number of different forms of under-reamers have been designed and are available from the tool supply companies. Of the various types on the market the Wilson pattern is perhaps best known (see Fig. 54).

The under-reamer is equipped with two lugs having specially formed and hardened cutting edges, mounted in the body of the tool in such a way that they expand outward under the influence of a powerful spring. The lugs are held in the collapsed position by a wire or light metal ring

while the tool is being lowered through the well casing, but on emerging from the casing shoe they are forced outward into working position by the spring. With lugs fully expanded some under-reamers are capable of drilling a hole 3 in. larger in diameter than that of the casing through which they pass.

The under-reamer is churned up and down in the same manner as the ordinary drilling bit, gradually enlarging the hole to the limit of expansion



(*Courtesy of Union Tool Co. and Byron-Jackson Co.*)

FIG. 54.—Wilson-type cable-tool under-reamer.

A, side and edge views; *B*, illustrating method of releasing lugs; *C*, illustrating under-reamer descending through casing with lugs collapsed; *D*, illustrating under-reamer at work, with lugs expanded, below casing shoe.

of the lugs. On withdrawing the under-reamer from the well, the lugs are compressed into the body of the tool against the pressure of the spring as they enter the casing shoe. The moderate side pressure of the lugs against the inner walls of the casing introduces slight resistance to withdrawal of the tool.

In operation, the brunt of the contact with the rock walls of the well falls directly upon the cutting edges of the lugs, which are consequently rapidly dulled. Care should be taken in dressing the lugs to give them a hard temper in order that they may better resist abrasion. If the steel

is too hard, however, the edges become brittle so that they break in service. Some operators find that a little hard fusion metal melted on the cutting edges of the lugs with an oxyacetylene torch greatly increases their useful life. Under-reamer lugs are frequently made of chrome or manganese steel, which are tougher and more resistant to abrasion than ordinary tool steel. The lugs are forged on special anvils or dressing blocks, recessed to conform with their peculiar shape.

Bailers, used in removing from the well the pulverized rock loosened by the bit during the process of drilling, are constructed of a pipe of

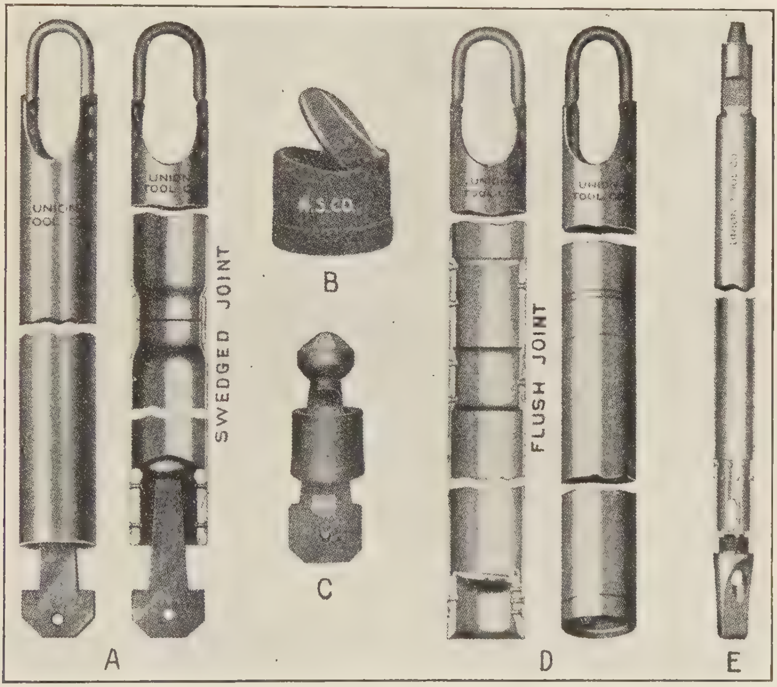


Fig. 55.—Types of bailers.

A, dart valve bailer; *B*, disk valve; *C*, dart valve; *D*, disk valve bailer; *E*, combination bit and mud socket.

suitable size in the lower end of which is fastened a reinforcing shoe and valve. At the upper end a bail is provided for attaching the sand line. Short bailers may be used when the well is shallow and large in diameter, but for great depths, and where the diameter of the well is small, the length must be increased to as much as 20 or 30 ft., occasionally even 40 ft., in order to handle a greater quantity of material with each trip of the bailer to the bottom.

Bailer valves are of two types. The disk valve is hinged at one side, opening upward (see Fig. 55). The dart valve is spherical or ovoidal in form and has attached to it, on its lower side, a metal stem or dart which passes through the circular valve seat and projects beyond the lower end

of the supporting shoe. In the case of either type of valve, upward pressure of the well fluid on the descending bailer raises the valve so that the fluid passes through until it rests upon the bottom of the well. The bailer is then raised and dropped a few feet ("spudded"), the process being repeated several times in order to force as much as possible of the sand and clay through the valve. On hoisting the bailer, downward pressure at once closes the valve so that even though the top is open no fluid is displaced. On emerging from the well, the bailer is dumped—in the case of a bailer equipped with a dart valve, by lowering it into a wooden trough, the upward pressure of the trough bottom on the dart lifting the valve from its seat, thus permitting the contents of the bailer to flow out. In dumping a bailer equipped with a disk valve, it is lowered over an upright metal pin mounted in the trough, which lifts the valve on its hinge.

The main body of the bailer is often made of well casing 2 or 3 in. smaller in diameter than the casing through which it must operate. Occasionally a spirally riveted sheet-metal pipe will be used for light service. If a long bailer is needed and more than one joint of pipe must be used, two or more sections may be connected end to end with swedged or flush-riveted joints. The bail and reinforcing shoe are also riveted in position on the ends of the pipe. The reinforcing shoe is of cast steel and is provided to prevent wear and distortion of the lower end of the bailer, which is subjected to considerable abrasion during the process of lowering and spudding it in the well.

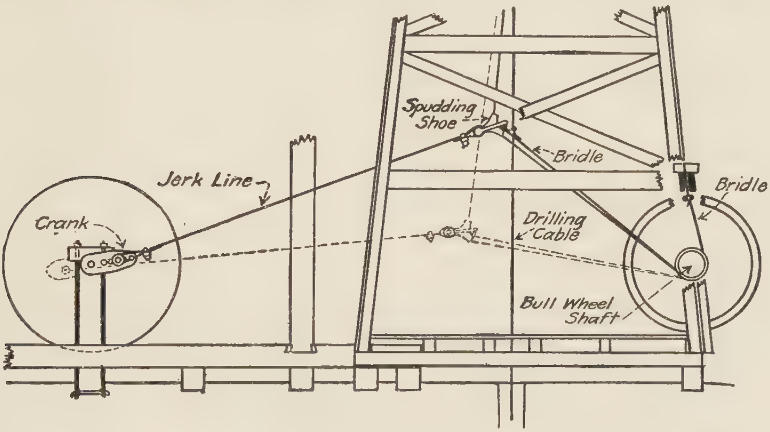
Sand Pumps.—If the fragments of rock loosened by the drill are coarse, they settle rapidly to the bottom and it will be difficult to get them into the ordinary type of bailer. For such conditions it is customary to make use of a sand pump, which is similar to an ordinary bailer in general construction and form except that it is provided with a piston or plunger which can be moved up and down in the cylindrical shell to create suction helpful in drawing coarse material past the valve. In one type of sand pump the sand line is attached to the top of a plunger rod instead of to the bail. A slot in this rod, straddling the bail, permits of the piston being raised a number of feet as the sand line is hoisted, before the plunger engages the bail and lifts the main body of the pump.

Mud Sockets.—When soft clay or mud must be penetrated by the well, or when such materials have had time to settle into a solid mass in the bottom of the well, the bailer is not always effective in removing them. They can be easily penetrated by the drill but settle rapidly before the tools can be withdrawn and the bailer lowered. In such cases a "mud socket" (see Fig. 55) may be substituted for the drilling bit on the bottom of the string of cable tools. This device consists of a heavy metal tube equipped with a beveled reinforcing shoe and inclined disk valve within the lower end. It is churned up and down within the well until full

of mud or clay, when it is withdrawn for cleaning. For work in very stiff muds or clays the socket is sometimes also provided with a sharp chisel-edged bit attached to the shoe in such a way that it does not interfere with the passage of material through the valve.

DRILLING WITH THE CABLE TOOLS

Spudding.—Since the complete string of cable tools is 40 ft. long or more, there is not sufficient head room to conduct drilling operations with the aid of the walking beam until a depth of at least 60 ft. is attained. The first 60 ft.—frequently several hundred feet—of the well is therefore drilled by a process known as "spudding," which does not involve the use of the beam. A special spudding bit is used which is shorter than the



(*After W. H. Jeffery, with additions.*)

FIG. 56.—Illustrating method of spudding.

usual pattern, and a short stem without jars. The drilling bit is lowered to the bottom of the cellar inside of the conductor, a little slack is allowed in the cable and the bull wheels are securely locked with the brake. A spudding shoe is then placed on the drilling cable a short distance above the bull-wheel shaft, and a jerk line connecting with the wrist pin on the crank is attached to the clevis of the shoe (see Fig. 56). With each revolution of the crank shaft, the tools are lifted a short distance and dropped on bottom. By occasionally releasing the bull-wheel brake and letting out more of the drilling cable, the tools may be kept striking on bottom. Progress is often slow by this method, but deficiencies of the method are usually offset to some extent by the soft character of the surface strata. Operation of the drilling tools must, of course, be occasionally interrupted to bail out the material loosened by the drill. It is preferable to use a manila drilling cable during the spudding process, since the action with a steel cable is somewhat detrimental to the rig, particularly if the rig is a light one.

"Hitching On."—When sufficient depth has been attained to permit of operating the full string of tools with the walking beam, the spudding equipment is removed, the temper screw is adjusted in position on the end of the beam and the complete string of tools with a regular pattern drilling bit is assembled. Care is taken, as the tools are lowered past the derrick floor, to set up each tool joint with the circle jack to make certain that all are tight. The tools are lowered by partially releasing the bull-wheel brake until bottom is reached. When lowering the tools into the well, the driller applies the bull-wheel brake at intervals of a few feet when nearing the bottom in order to stop the descent just as the tools reach bottom on the full stretch of the cable. In drilling, the tools should strike bottom while the cable is extended to the limit of its elasticity, thus insuring the maximum rebound. This elastic rebound probably increases the effective stroke of the tools by several feet under favorable conditions and is also effective in promptly freeing the bit from clay or loose material in the bottom of the hole and in keeping the cuttings in suspension in the well fluid.

With the tools suspended from the crown pulley in the proper position, as determined by "springing" the line as described above, the engine end of the walking beam is raised and the pittman attached to the crank with the wrist pin in the third or fourth hole and with the crank at the top of its arc. With the temper screw gripped in the highest position in its frame, the temper-screw clamps are then firmly attached to the drilling cable, the bull-wheel brake is released and sufficient slack cable is pulled over the crown pulley to prevent jerking of the cable above the walking beam as the latter oscillates. The weight of the tools is thus transferred from the crown pulley to the walking beam, and as soon as the engine has been centered all is in readiness for drilling.

The Mechanics of Drilling with the Cable Tools.—The engine is started, and as the beam oscillates, the driller, with his hand on the drilling cable, notes the vibration or "jar" which to the skilled observer indicates the manner in which the tools are operating. Slight adjustments in the position of the temper screw or in the speed of the engine are made until the tools are striking with the maximum force on the bottom of the hole.[1]

Satisfactory progress depends to a large extent upon the ability of the driller to interpret the vibrations that come to him through the drilling cable. The novice sometimes "loses the jar" and works for hours without making any progress. The tools may be standing on bottom while he is playing with the slack in the cable, or they may be swinging several feet off bottom. The skilled driller will know as soon as his hand touches the drilling cable whether the drill is working properly or not.

The jar which the driller feels in the cable is the result of alternate release and application of tension in the drilling cable as the beam rises and falls. Because of the elasticity of the cable, it is probable that the beam is already returning on the upstroke as the tools strike bottom, the result being a distinct jar in the cable as the tools rebound, usually of sufficient intensity to cause vibration of the rig. In addition

to the jar, to the sensitive hand of the driller on the cable there is a perceptible "reach" and "lift" of the cable as tension is applied and released. As explained above, the tools strike bottom with the cable under tension, the amount of tension depending upon the elasticity of the cable and the extent to which the tools have to reach for bottom. When the tools strike and rebound, the same elasticity causes a contraction of the line, giving the sensation of lift. The action of the tools may be compared with the bounding movement of a small weight churning up and down while suspended on the end of a rubber band. The tools reach down on the stretch of the line and strike a springing blow, rebounding rapidly. As the tools begin to reach for bottom and the "jar works off," the driller "tempers the jar" by lowering the tools with the temper screw.

The speed of the engine and length of stroke of the beam have much to do with the action of the tools. As the well attains greater depth, it is necessary to lengthen the stroke by moving the wrist pin farther from the center of rotation of the crank. For a given length of cable and of stroke, there is a certain periodicity which determines the speed at which the engine should operate. Overspeeding of the engine will result in jerking the tools upward before they strike, subjecting the cable and tools to a destructive strain which often causes breakage of the jars or parting of the drilling cable. Such action of the tools also induces a jerky motion in the engine until it becomes unmanageable. Catching the tools in this way is one of the common difficulties of the unskilled driller. Too slow a motion, on the other hand, will greatly reduce the force of the blow struck by the tools.[1]

Power control becomes increasingly difficult as greater depths are attained. This is a direct result of the greater weight of cable to be lifted and the greater elasticity of the longer cable. This loss of effectiveness of the engine is offset to some extent by lengthening the stroke, or by use of the engine balances on the rim of the flywheel. With an ordinary drilling engine, great skill in steam control is necessary to operate the tools effectively at depths in excess of 2,000 or 2,500 ft. without the use of engine balances. Satisfactory operation of the engine requires a slightly greater speed on the downstroke of the tools than on the upstroke. This results naturally from the alternate release and application of the load on the engine. When balances are used on the engine flywheel, however, a more uniform speed results, which to some extent retards the drop of the tools and compels a slower motion. Hence the use of the engine balances should be avoided until made necessary by the jerky action of the engine.

The action of the tools will vary with the kind of cable used. Hemp cable has greater elasticity than steel and will reach for and strike bottom long after the steel cable under similar conditions will have ceased to strike. The steel cable, when unduly stretched, will often "peg leg," that is, the tools will alternately strike bottom and miss. Hemp cable has more "lift" than steel, a characteristic which, as we have seen, depends upon the elasticity of the cable. Both lift and peg legging are to a great extent dependent upon depth. The remedy is an extension of the temper screw. The action of the tools will also vary somewhat with the amount of water in the hole. Water, of course, retards or damps the motion of the tools, its effect being particularly noticeable in drilling "wet" holes with hemp cable of large diameter. Drilling with the hemp cable requires greater skill on the part of the driller than when steel cable is used.

Opportunity was afforded for observing the effect of elasticity in the drilling cable in one instance where a churn drill hole intersected underground mine workings at a depth of 500 ft. A hemp cable was used with a 36-in. stroke at the walking beam, but at a depth of 500 ft. the actual length of stroke of the tools was in excess of 8 ft. The elastic rebound of the tools also varies markedly with the character of the rock in which the bit is working, being appreciably greater in hard rocks than in semiplastic

clays and shales. Because of the reach of the cable in drilling, it is probable that in most cases the hole is actually several feet deeper than the normal length of the drilling cable and tools.

With some types of rocks, best results are obtained by operating the tools "tight hitched," that is, allowing them to strike only on the extreme elastic stretch of the cable. In other cases, "loose hitching" gives best results. The tools should always be tight hitched when drilling through hard, steeply inclined strata because of the tendency of the bit to follow the dip of the strata, thus drilling a crooked hole.

The impact of the heavy cable tools on the bottom of the well when the tools are dropping freely is enormous. Let us assume that a 10-in. hole is being drilled. The weight of the tools will probably aggregate about 3,600 lb. for this size of hole. The length of stroke or sweep of the walking beam will be, say, 3 ft. Add to this the stretch or spring in 2,000 or 3,000 ft. of drilling cable and we have a total drop for the tools of perhaps 5 or 6 ft. Multiplying the lower figure by the weight of the drilling tools (3,600 lb.), we obtain 18,000 ft.-lb. of work exerted on the formation at each stroke. When it is considered that this impact is repeated at the rate of perhaps 30 strokes per minute on an area of not more than $\frac{3}{10}$ sq. ft. (approximate area of the end of a 10-in. bit), it is apparent that we have to deal with a crushing force of considerable magnitude.

Because of the shape of the end of the bit and the absence of a sharp cutting edge, it is probable that there is comparatively little actual chipping or cutting of the rock, but rather a crushing action which breaks down the rock mass into small fragments. The shape of the disintegrated material will vary with the nature of the rock, being granular in the case of sandstones and amorphous rocks, and platy in the case of thin laminated strata and in rocks possessing well-developed cleavage. The material brought to the surface in the bailer is generally finely pulverized by repeated pounding of the bit on the larger fragments after they are detached from the main rock mass. The walls of the well are probably left rather rough as a result of the action of the bit, and the material in the walls will be badly fractured except in the case of very hard, tough rocks. Because of this, in soft formations the walls tend to cave. The walls are sustained to some extent, however, by the action of clay which accumulates from the sludge between the rough projections on the walls, plastering over the fractures and preventing to some extent further disintegration.

Drilling with the Jars.—In drilling through beds of sticky clay or in caving formations, it is often necessary to bring the jars into play in order to effect release of the bit on the upstroke of the tools. Drilling jars are attached above the stem and usually have a stroke varying from 4½ to 12 in. In drilling, the jars are permitted to telescope for only a part of their maximum stroke, say, for 4 or 6 in. This displacement permits the upper link to gain considerable momentum on the upstroke before picking up the bit and stem. Such action provides the necessary sudden upward jerk to free the bit from sticky material in the bottom. A skillful driller never allows the jars to strike on the downstroke except in certain fishing operations when a jar-down effect is desired.

Rotating the Tools.—In certain kinds of rock, the cable tools have a tendency to drill a flat hole, that is, the well becomes elliptical in cross section. This can only result from the bit striking repeatedly in one position. Since the bit is wider than it is thick, such action is inevitable unless the bit revolves as it operates. Formerly drillers considered it necessary to twist the cable slowly at the temper screw as the tools churned up and down in the well, but the efficacy of this practice is questionable in view of the great length of cable that often exists between the temper screw and the tools. Many drillers insist on the use of a ratchet or swivel type of rope socket, which is supposed to permit of easier rotation of the tools and allows twists in the drilling cable to readjust themselves independently of the tools. An innovation is the use

of the spiral-winged drill stem to aid in securing positive rotation of the tools as they rise and fall through the well fluid. It seems reasonable to expect that the spinning of the tools induced by alternate application and release of tension in the cable would be sufficient to prevent the tools from striking repeatedly in the same position except, perhaps, at very shallow depths. If the tools fail to rotate, it is probably due in most cases to loose material accumulating on the bit or on two opposite sides of the hole, and more frequent bailing or a more rapid motion of the tools should remedy the matter.

Flat holes are particularly likely to occur when drilling through water sands. "Tight" holes, which result from loss of gage by wear on the sides and corners of the bit, are also characteristic of such material, and for this reason water sands are generally under-reamed. The bits should be frequently redressed if proper clearance for the casing is to be maintained.

Bailing.—Continued operation of the drilling tools results in accumulation of cuttings in the bottom of the well, which will eventually so restrict the motion of the tools that little or no progress is made. Such a condition requires removal of the drilling tools and operation of the bailer.

To "draw out the tools," the bull wheels are first revolved by hand until the slack cable over the crown pulley has been wound on the bull-wheel shaft. The bull ropes are then thrown on, causing the wheels to revolve under the influence of the power and hoisting the tools in the well until the load is transferred from the temper screw to the crown pulley. The driller then promptly throws off the bull ropes and clamps the bull-wheel brake while his helper stops the engine. While this is being accomplished, both the walking beam and the bull wheels are in motion, and, unless the power is disengaged at the proper time, damage to the rig will result.

The temper-screw clamps are then removed from the drilling cable, and the pittman is taken off the wrist pin and lowered to the plank walk. This elevates the end of the beam overhanging the well and places it out of the way of the drilling tools and bailer as they are run into and out of the well. The bull ropes are now again placed in position on the bull wheels and power is applied, raising the tools until they emerge above the derrick floor; the bull ropes are then thrown off and the tools are caught and suspended above the well by clamping the bull-wheel brake when they can be swung over into one corner of the derrick.

Manipulation of the sand-reel reach draws the friction pulley forward against the face of the band wheel, thus causing the sand reel to revolve and lifting the bailer until it swings freely above the derrick floor. Reversing the position of the reach causes the friction pulley to bear against its brake post so that the bailer can be held suspended in any desired position. The lower end of the bailer is guided into the well, the brake is released and the bailer is allowed to descend rapidly, braking occasionally, until bottom is approached, when the descent is brought under close control by further application of the brake.

The bailer is raised a few feet and lowered to bottom several times to make certain that coarse material accumulated near the bottom has had ample opportunity to pass the bailer valve. It is then withdrawn as rapidly as possible by bringing the sand-reel friction pulley to bear against the face of the revolving band wheel. On reaching the surface, the bailer is suspended with the lower end a little above the derrick floor by shutting off the power and applying the brake. The loaded bailer is then swung to one side from its position over the well and lowered (by partially releasing the brake) through a hole in the derrick floor into a wooden trough placed immediately beneath. As the bailer valve is raised by downward pressure of the dart on the bottom of the trough (or by a metal rod mounted vertically in the trough in the case of disk-valve bailer), the content of the bailer flows out and may be inspected to determine the nature of the material. The power is then applied, rais-

ing the bailer until it clears the derrick floor, when it may be swung over into one corner of the derrick and held out of the way by a metal hook or rope sling, or it may be lowered into the well for another load of sludge. Usually several trips to bottom with the bailer will be necessary before the well will be sufficiently cleared to resume drilling operations. The process of lowering the tools and of attaching the temper screw as described above must then be repeated.

Replacing a Worn Bit.—Continued use dulls the cutting edge and corners of the bit and reduces its gage so that it no longer drills a hole of the desired diameter. It must therefore be occasionally replaced with a properly dressed and gaged bit. When slow progress warns that the bit has become dull, the tools are drawn out as described above under Bailing. As the tool joint between the drill stem and the bit emerges from the well above the derrick floor, the power is shut off and the tools held sus-

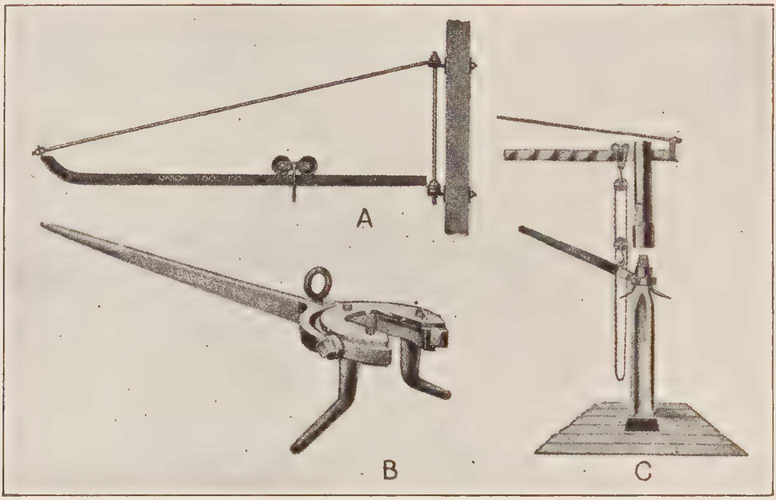


Fig. 57.—Derrick crane (*A*) and swivel wrench (*B*) for supporting drilling bit (*C*).

pended (with the bit in the well) by clamping the bull-wheel brake. The tool joint is loosened by application of the circle jack and the power again applied until the bit swings free above the derrick floor. The bit is then unscrewed from the stem with the aid of hand wrenches if necessary, and a fresh bit is screwed to the stem in its place. The heavy bits are conveniently supported, before attaching to and after disengaging from the stem, by means of a swivel wrench hung horizontally, suspended on chain blocks from a derrick crane (see Fig. 57). Such a crane can be swung to any desired position over a radius of 10 ft. from the post in one corner of the derrick to which it is attached. The wrench supported on its chain hoist is suspended from a small two-wheeled trolley which may be moved to any desired position along the horizontal beam of the crane. On lowering the sharpened bit into the well, the tool joint connecting it with the stem is "set up" with the aid of the circle jack.

The Routine of Drilling with the Cable Tools.—Unless some accident occurs to interfere with the operation of the tools, the routine of the work becomes rather monotonous. The equipment is usually operated day and night, with either two or three crews of men working 12 or 8 hr. respectively. Each crew consists of two men, the driller, who is in responsible charge of the work, and his helper or tool dresser. The

work is divided into alternate periods of drilling and bailing, with occasional interruptions to insert casing (see Chap. VIII).

The frequency of bailing depends upon the nature of the material in which the drill is working. Frequency of bailing also depends upon the rate of progress and the extent to which the material loosened by the bit remains in suspension in the well fluid. Certain kinds of clays and soft clay shales require frequent bailing, perhaps for every 2 or 3 ft. of progress. In hard rocks, on the other hand, the hole may be advanced for several lengths of the temper screw without necessity for bailing.

If it is unnecessary to bail when the full length of the temper screw has been let out, the engine is stopped and the weight of the tools is transferred to the crown blocks (as described under Bailing), while the temper-screw clamps are loosened from the cable and the screw is raised for a new grip on the cable. The clamps are then attached in the new position, the weight is transferred back to the beam (as described under Hitching On) and drilling is resumed. The temper screw can ordinarily be extended about 5 or 6 ft., so that the procedure outlined for taking a new hold on the cable need only be repeated at this interval.

Unless water enters the well from the formations penetrated, sufficient must be poured in at the surface to form a thin sludge with the material loosened by the drill. Practice differs as to the depth of fluid maintained in the well. In "dry-hole" drilling, as commonly practiced in the fields of the eastern United States and in some of the Mid-continent, Texas and Rocky Mountain fields, only sufficient water is used to keep the drill cuttings from clogging the bit; but in some of the California fields the hole is maintained full or nearly full of water, to aid in preventing the walls from caving. Dry-hole drilling is preferable since the tools develop their maximum efficiency when movement is not impaired by friction of the drilling cable on a long column of water, and by the buoyant effect on the tools; but where the walls have a tendency to cave, or where "heaving" formations are to be penetrated, the pressure of a long column of water is of considerable assistance. Long strings of heavy casing may also be more readily handled in a hole full of water.

The Speed of Drilling.—The number of strokes per minute at which the drill can be operated will depend upon the depth of the well, the diameter, the depth of fluid in it and the nature of the material in which the bit is working. Generally speaking, great depth, small diameter, great depth of fluid or soft material necessitates a slow motion. The number of strokes per minute will ordinarily range between 20 and 40.

The rate of progress in cable drilling will vary within wide limits. Varying character of the formations penetrated, the depth of the well, its diameter and time lost in inserting casing and cement and in fishing operations are important variables that influence the rate of progress. In soft rocks at shallow depths, an advance of 100 ft. or more may be

made in a 24-hr. day, under favorable conditions. In a hard layer of "shell" (any hard rock), 5 ft. of hole may represent a good day's work. The rate of progress also depends largely upon whether or not the walls stand without caving and whether the material penetrated tends to heave or flow into the well. The depth of the well influences the rate of progress in two ways: in a deep well, the tools do not work so satisfactorily and must be operated at a slower speed, and more time is consumed in drawing out and lowering the tools and bailer. The tools do not drop so freely in a hole of small diameter, particularly if it is filled with water. Hence a slower drilling speed must be adopted and progress is slower. Any interruption in the usual routine of drilling, of course, greatly influences

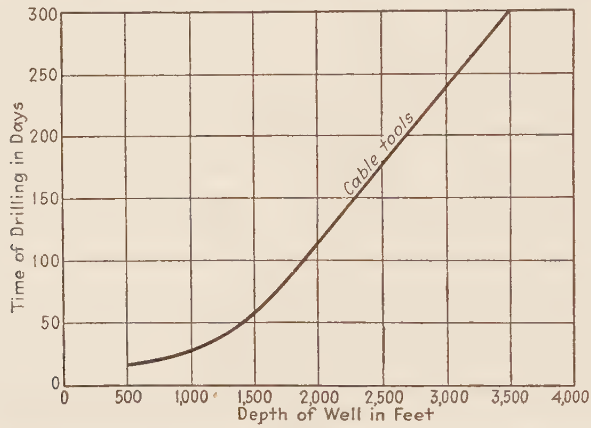


Fig. 58.—Graph showing time consumed in drilling to various depths with cable tools, California fields.

the average footage drilled per day. Casing may have to be underreamed or driven past tight places in the hole. Breakage of the tools or parting and collapsing of the casing may necessitate a fishing job of several days' or even weeks' duration, during which no increase in depth is attained. When cement is introduced into the well to exclude water, an interval of at least several days is allowed for the cement to set and harden before drilling is resumed.

In the San Joaquin Valley fields of California, a region characterized by comparatively soft formations, up to moderate depths (say 1,500 ft.) progress will average about 30 ft. per day with a maximum of 60 to 70 ft. and a minimum of 5 ft. At depths in excess of 3,000 ft. in the same region, 15 ft. per day is a good average rate of progress, with about the same minimum and a maximum of, say, 30 or 40 ft. In a 1,350-ft. hole drilled in the black shales and lime of north central Texas—an unusually hard formation—progress averaged 27 ft. per day, a high average for this kind of rock. The graph reproduced in Fig. 58 indicates average rates of drilling for cable tools in the San Joaquin Valley region of California.

Identifying Formations and Gathering Log Data with the Cable-tool Equipment.—The cable-tool driller is able to identify the kind of rock in which the drill is operating by the rate of progress, by the jar on the drilling cable and by the wear on the drilling tools. Cuttings brought

TABLE XVII.—MECHANICAL REACTIONS ON CABLE-TOOL DRILLING EQUIPMENT AND CHARACTER OF CUTTINGS OBTAINED FROM DIFFERENT TYPES OF SEDIMENTARY ROCKS*

Field and formation	Mechanical reactions	Cuttings	Effect on bit
Southern Oklahoma:			
Shale	Tools run smoothly and drill easily and fast in dry hole.	Bailer material mostly mud; fragments in mud and occasionally on bit.	Does not wear bit.
Gumbo	Drills roughly; tools jerk walking beam and do not drop freely.	Bailer material mud; tools come out loaded with gumbo.	Does not wear bit.
Soft sand	Drills fast and easily; tools plunge.	Sand in bailer; none on bit.	No wear on bit, but markings vertical.
Sandstone	Drills smoothly with occasional "kick back."	Grains of sand and chunks of sandstone in bailer.	Wears bit out of gage.
Limestone	Hard and slow drilling; big "kick back."	Chips and irregular pieces, rock mostly pulverized.	Wears bit, but does not cause to lose gage like sandstone.
Gypsum	Drills smoothly and more easily than crystalline limestone.	Mostly pulverized; occasional flakes.	Does not wear bit excessively.
Ranger field, Texas:			
White limestone	Drills hard but free, with tight line.	White and pulverized.	Cuts bit badly—3 bits per tour.
Shale	Drills fast and easily in dry hole.	Chunks and fragments in bailer and small pieces stuck to bit.	Does not cut bit.
Black limestone	Drills hard, with tight line through oil saver.	Cuttings fine grained.	Cuts bit a little.
Wyoming fields:			
Hard shell	Drills clean with increased motion.	Occasional fragments in bailer.	Does not wear bit rapidly; cuts it vertically like sand.
Limestone	Drills clean with increased motion.	Cuttings fine grained and heavy.	Does not wear bit badly.
Shale, slate, etc.	Drills fast in dry hole, except when cavy. Slow motion.	Fragments of material in bailer.	Very little wear, but "dubs bit under."
Sandstone	Drills clean and free.	Cuttings show as sand grains and fragments of cemented grains.	Cuts bit badly, vertically.

* After R. E. Collom, U. S. Bur. Mines, *Bull.* 201.

up by the bailer, when thoroughly washed to free them of mud, provide a means of identifying accurately the nature and mineral content of the rock. Usually, too, a little of the material in the bottom clings to the drilling bit as it is withdrawn. Table XVII indicates the mechanical reactions and character of the cuttings obtained from different types of sedimentary rocks. The material brought up by the bailer is mostly

mud, but by carefully stirring and washing a little of it in a bucket the coarser material may be segregated and examined.

Depth to bottom is determined at any time, either by actual tape measurement, by measurement of the drilling cable or sand line or by recording the length of casing in the well, if the casing extends to bottom. For shallow wells a heavily weighted steel-wire tape coiled on a reel mounted at one side of the well may be lowered to bottom and the depth measured directly. In deep wells the magnetic drag of the tape on the casing is frequently so great that it is impossible to tell when the weight reaches bottom or to feel the "pick-up" as the weight is lifted off bottom. Measurement on the drilling cable or sand line is probably more accurate if carefully done. For this purpose, the distance from the derrick floor over the crown and down to the upper flange of the sand reel, or to a point on the bull-wheel shaft 5 ft. above the derrick floor, is carefully determined by tape measurement, and one or the other of these units is applied on the sand line or drilling cable respectively, as described on page 396. Measurements are made while drawing the bailer or tools out of the hole, care being taken to record bottom on the pick-up, that is, just as the sand line or cable receives the full weight of the bailer or tools on leaving bottom. If depths are determined by the casing record, an accurate measurement of all casing in the hole must be kept, lengths being measured from top to top of collars after the joints are securely screwed together.

The driller usually maintains a "target" or reference mark on the sand line or drilling cable, indicating the approximate depth to bottom, depths in excess of the reference mark being measured with the aid of a steel tape or a 5-ft. "stick," which is a part of the equipment of every cable drilling rig. Examination of well logs will show that many drillers do not attempt measurements within the 5-ft. length of the stick. Measurements involving lengths in excess of 100 or 200 ft. should not be attempted with the stick because of the inaccuracies involved. Measurement with the steel tape is always preferable. Usually the driller knows the depth to bottom at the beginning of each "screw," and when a change in formation is noted by the action of the drilling cable he has only to measure the length of temper screw paid out to record the depth at which the new formation was encountered.

CABLE-TOOL CORING DEVICES

When better samples are desired of the formation in which the drill is working than are afforded by the drill cuttings brought to the surface by the bailer, recourse may be had to the use of a cable-tool core barrel. This is a special drilling tool which is run below a set of jars in place of the usual drilling bit. Figure 59 illustrates two successful types of cable-tool core barrels. The Baker Standard core barrel, illustrated in Fig.

59*A*, consists of two main parts: an outer drilling barrel and an inner core-retaining tube. The drilling barrel is composed of three essential parts: a drill-barrel head *A*, a drill barrel *B*, and a drill-barrel shoe *C*. The core-retaining tube is also composed of three parts: a core-tube head *D*, a core tube *E* and a core-tube trimmer shoe *F*. In action, the lower end of the core-retaining tube rests in a stationary position on the bottom of the well, while the outer barrel churns up and down about it as a guide, striking bottom on each downward stroke. Circulation holes *G* are provided, leading inwardly to a chamber within the drill-barrel head, which is closed at its lower end by a back-pressure valve *H*, which opens downward. This valve opens on the upstroke of the drill, permitting the well fluid to enter the barrel. This valve action confers an hydraulic effect upon the water within the outer barrel on the downstroke, causing it to flow down into the core-tube head, whence it escapes through ports *I* into the annular space between the drill barrel and the core tube and out into the well between the core tube and the drill-barrel shoe. This circulation of fluid between the inner and outer barrel prevents clogging and keeps the bit free of the barrel. A second valve *J* of ball-check type, is used in the top of the core tube to prevent circulating water from entering the core tube and yet permit fluid contained within the core tube to escape as the core enters. This valve is firmly seated on the downstroke by the downward hydraulic pressure and is held in position by gravity on the upstroke. The drill-barrel shoe is made with a clearance at the cutting edge to allow the barrel to drop freely in the hole. The cutting teeth are spaced irregularly and are faced with a hard facing metal. It is connected to the lower end of the drill barrel with a special tool-joint thread, and being smaller than the inside diameter of the drill barrel a shoulder is formed which prevents removal of the inner core-retaining tube. The latter has a shoulder at its upper end. The core-tube trimmer shoe is screwed on the core tube and is made with a sharp-beveled edge, which is faced with a special alloy metal. A tapered, split trap ring *K* is mounted on the inside of the trimmer shoe.

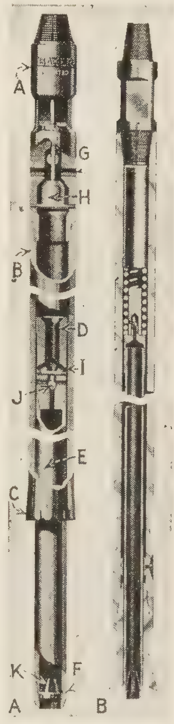


FIG. 59.—Cable-tool core barrels.

A, Baker core barrel; *B*, Elliott core barrel.

Figure 59*B* is illustrative of the Elliott cable-tool core barrel. This device also makes use of an inner core-retaining barrel, which is supported within an outer drilling barrel. The bit is of star form and is of special heat-treated steel. The inner barrel is of seamless tubing, 10 ft. long, and supports a special shoe and core catcher at its lower end. A weight-

retaining ring attached to the inner wall of the outer barrel prevents the inner barrel from falling out when the tool is being lowered or raised into or out of the well. A valve, mounted on the upper end of the inner barrel, permits escape of the well fluid as the core enters. Above this is a spring and adjustable weight. In operation the inner shoe remains on bottom, while the outer barrel and bit rise and fall with the motion of the beam. As the hole is deepened, the inner core barrel is driven down over the core. On withdrawing the tool, the core catcher grips the core and prevents it from falling out.

The cable coring tools should be operated in at least 30 ft. of fluid and with a somewhat slower motion than is usually employed when drilling with the ordinary bit, and the stroke used must not be so great that the core barrel is raised off the bottom of the hole. From 4 to 7 ft. of core may be cut at one time, but best results are obtained by not exceeding 5 ft. The cores are seldom in long sections as is the case with diamond drill cores but are customarily in "biscuit" form, or in short cylinders ranging from ½ to 2 in. in thickness. The cost of coring with the cable tool ranges from as little as 40 cts. to $4.75 or more per foot. Upward of 95 per cent of the footage drilled may be recovered as core under favorable circumstances. Cable-tool core barrels have been used in recent drilling in the Appalachian and Rocky Mountain fields of the United States.

PORTABLE AND SEMIPORTABLE RIGS FOR CABLE DRILLING

For prospecting work, and for drilling wells in shallow territory—even up to depths of 2,500 ft.—portable and semiportable drilling machines are often used. These are much lighter than the standard cable rig described in the foregoing pages but operate on the same principle and often by quite similar equipment. Instead of a derrick, these portable rigs are generally equipped with a braced mast and the machinery is mounted on a four-wheeled truck or on a light timber-frame structure that can be readily moved about as a unit from one location to another and put in condition for active service within a few hours' time. The trucks are sometimes of the self-tractor type so that they can be moved about under their own power.

Each part of the standard cable rig has its counterpart in most of these portable rigs, often changed in form and size, however, to adapt it to use in a smaller space and to render it more readily transportable. There is necessarily some form of a walking beam or spudding device to impart the churning motion to the drilling cable. There must be two hoisting drums on which the drilling cable and sand line are wound, and there must be a source of power with means of distributing it to the different parts of the rig. Some of the heavier rigs are equipped with an additional drum for handling casing. Usually, however, the drilling cable is used for handling casing. A steam engine and boiler furnish the power in most cases,

though occasionally a gasoline engine will be used. The latter type of engine is simpler as a power unit, and occupies less space, but is not so well adapted to the work of drilling as the steam engine. The drilling tools and incidental equipment are quite similar to those used in connection with the standard cable outfit, except that they are usually smaller and lighter.

Probably the greatest difference to be noted in the several types of portable and semiportable rigs is found in the design of the mast. The mast serves the same purpose as the derrick and must therefore provide a support at a suitable elevation for the sheaves used in changing the direction of the drilling cable, sand line and casing line. Two types of masts are in common use: (1) the single-post mast, which consists of a single heavy timber mounted on end on the ground or on one end of the truck on which the machine is mounted; and (2) the two-legged braced mast, built of metal channels latticed together, or of two heavy timbers, suitably braced by horizontal girts and mounted on the sides of the truck. In some cases the mast is entirely independent of the drilling mechanism. It is often built in sections to facilitate transportation, the sections being readily assembled and disassembled. The braced mast can be built of lighter material than a single-post mast of the same strength and if properly designed should be more rigid. In either case the mast is slightly inclined from the vertical to bring the sheaves at the top clear of the supports and must be braced with guy wires in several directions to near-by stakes driven in the ground.

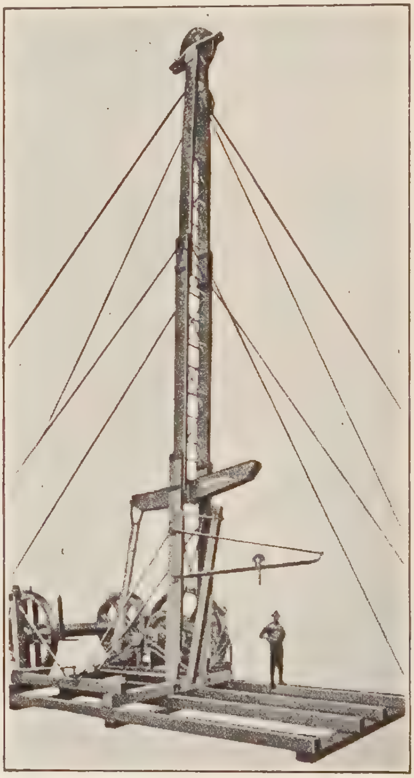
Of the many drilling machines in use, the Star and Columbia drilling rigs are probably best known in the group of portable machines, while the National rig is the best known of the semiportable type. A brief description of each of these will serve to acquaint the reader with the main features of portable and semiportable drilling equipment. The reader is referred to the manufacturers' catalogues for more detailed information on these and other rigs.

The Star portable drilling machine is made in a variety of sizes, all mounted on four-wheeled trucks, the heaviest model (No. 30) being rated by the manufacturers for drilling to depths as great as 4,000 ft. The heavier models are all equipped with vertical reversible steam engines and boilers, but several models equipped with gasoline engines are also available for drilling to depths of less than 1,000 ft. The latter are of the self-tractor type.

The No. 30 Star machine (see Fig. 60) is equipped with a 60-ft., single-pole timber mast, sectionalized to facilitate transportation, with additional shear poles provided for bracing the mast when very heavy lifting is necessary and 12 guy wires. Three pulleys are mounted on or near the upper end of the mast to support the drilling cable, sand line and calf line. A walking beam 22 ft. long is mounted on a slanting Samson post at one corner of the truck and heavily braced to one side. The 35-hp. steam engine is mounted at the same end, a belt connecting from its flywheel to a 92-in. wooden band wheel, mounted on one side of the truck and serving as a power-distribution center for the entire machine. In the case of the model 30, the boiler is mounted on a separate wheeled truck, but in smaller sized machines it is carried on the end of the same truck that supports the drilling machinery. A crank mounted

on the band-wheel shaft operates the walking beam through a connecting wrist pin and pittman. The 60-in. bull wheel or drum, supported at the center of the truck and driven by gearing from the band-wheel shaft, is equipped with a reel large enough to spool 2,500 ft. of 2¼-in. hemp cable, and with a heavy band brake. A sand reel driven by a belt from a countershaft, operated by a friction pulley bearing on the face of the band wheel, actuates the bailer. A calf wheel for handling casing is also built into the machine. This is operated by gearing from the band-wheel shaft. Instead of suspending them from a temper screw on the end of the walking beam, the

(Star Drilling Machine Co., Akron, Ohio.)
FIG. 60.—Star portable drilling machine.



(National Supply Co., Toledo, Ohio.)
FIG. 61.—National semiportable drilling rig.

drilling tools may, if desired, be operated by a spudding attachment mounted in a slot on the crank.

The weight of the No. 30 Star machine complete with boiler and tools is about 52,000 lb., too heavy to move without partially dismantling except on very well-built roads. The main frame of the truck is 6 ft. wide by 23 ft. long. It is claimed by the manufacturers that this machine is the equal in every respect of a heavy standard cable rig, being capable of handling the same-sized tools and an equal weight or length of casing. The model 30 machine described above is used less than the lighter and medium-sized machines designed for shallower depths. Some of the lighter rigs weigh only 7,000 lb. One commonly used medium-sized machine (No. 26), designed for drilling to 2,200 ft., weighs about 27,000 lb., and with tools and incidental

equipment about 35,000 lb. One well 2,825 ft. deep was drilled with a No. 26 machine in 45 days.

The Columbia driller is an all-steel, portable machine designed to supplant the stationary cable-tool rig commonly used in drilling oil wells to shallow and moderate depths. The larger sizes are rated for nominal depths as great as 2,000 ft. They may be had equipped with either steam or gasoline engines, and some sizes have a traction drive. Weights range from 4,000 to 26,500 lb.

A belt-driven band wheel, a bull-wheel drum driven by a large gear wheel operated from the engine crank shaft and a sand reel for operating the bailer are provided in all models and a calf-wheel attachment operated by a chain and sprocket drive may be added if desired for handling casing. Distinctive features of this machine include the cross-connected, double, steel walking beams, each mounted on a well-braced Samson post located one on either side of the truck, and the two-legged braced steel mast mounted at one end of the truck with the legs between the walking beams. The mast is built with a knee joint, so arranged that it can be lowered and carried on top of the truck when the rig is being moved. The Columbia machine may also be used to operate a rotary drilling table, which is provided as an additional attachment if desired. A duplex slush pump is necessarily also a part of the equipment if the rotary outfit is used. With the rotary attachment the Columbia machine thus becomes the equivalent in every essential respect of a light "combination" stationary rig.

The National semiportable drilling rig resembles more closely the ordinary standard cable rig than do the machines mounted on wheeled trucks described above. The chief difference in comparison with the standard rig lies in the use of a braced, two-legged mast instead of a derrick and a more compact arrangement of the rig wheels and parts. The rig wheels and controls are mounted on a bolted wooden frame and are of such weight and so compact that the whole machine can be placed on a truck and moved as a unit from one location to another. The mast is built in sections which can be readily dismantled or assembled. The walking beam, instead of being mounted on a Samson post, is supported on trunnions between the two legs of the mast. The machine is built in two sizes, No. 1 for drilling to a depth of 1,600 ft. and for handling a 17,000-lb. string of casing and No. 2 for drilling to 2,500 ft. and handling 30,000 lb. of casing.

The No. 2 machine is illustrated in Fig. 61. Power is received from an engine (not a part of the equipment) by belt on a wooden band wheel 10 ft. in diameter. Both the 7-ft. bull wheels and the sand reel are operated by a wooden friction drum 5 ft. in diameter with a 16-in. face, mounted on the band-wheel shaft. A hoisting drum for handling casing, which can be adapted to the rig if desired, is operated by a chain-and-sprocket drive from the end of the band-wheel shaft and is equipped with a clutch and a heavy band brake. The braced mast is about 65 ft. high and is made up of 12-in., 20.5-lb. channel steel, suitably braced, and built in three sections. Timber masts of similar design may also be had if preferred. At the upper end of the mast, a 43-in. crown pulley is supported and smaller sheaves are provided below for the sand line and casing line. The mast is hinged to one of the oak sills for convenience in hoisting it into position, the power being used to assist in this operation. The walking beam, supported between the mast legs, is operated by a pittman attached by a wrist pin to the crank mounted on the end of the band-wheel shaft. The beam is considerably shorter than that provided in the standard cable rig. This method of supporting the walking beam, and the friction drive used for operating the bull wheels, are the distinctive features of the National rig.

Advantages and Disadvantages of Portable Rigs.—The portable rigs have certain well-defined advantages and limitations. For drilling in

shallow territory, the cost of the well may be materially reduced since there is no necessity for the building of a derrick or other expensive fixed surface plant. Shallow wells can often be operated in multiple with a simple pumping jack at each well, and such repairs as are necessary after the well becomes a producer may also be handled by a portable pulling outfit mounted on a truck. Under such conditions the portable rig has become a serious competitor of the standard rig. For prospecting work, where the formations to be tested are within reach of the portable machines, they have the great advantage of ease in transportation. They are more readily dismantled and reassembled and therefore have a relatively greater salvage value after drilling a dry hole.

One of the serious disadvantages of most of the portable rigs is found in their inability to handle satisfactorily the heavy strings of casing necessary in drilling through unconsolidated sands and caving formations. In many regions where the tools can be operated in uncased holes to great depths this limitation is of course not a serious matter. Some of the manufacturers, in striving to adapt their machines to more difficult conditions, are giving attention to this phase of the work and have added calf drums which, while mechanically weak in most cases, are a step toward a real solution of the difficulty. Another disadvantage in comparison with the standard rig is the relatively short stroke of the walking beams or spudding devices provided in most of the portable machines. The beams are usually from 2 to 6 ft. shorter; and at depths greater than 1,500 ft., when stretch in the cable becomes a factor of importance, the effective stroke of the tools becomes so short that the portable rig is much less efficient. Though some of these rigs are rated by the manufacturers for depths in excess of 3,000 ft., it is doubtful if many operators would undertake the drilling of a deeper hole than this with a portable rig. The principal field of most of the portable rigs, as at present designed, would appear to be in drilling wells in formations that do not cave readily and to depths not greatly in excess of 2,500 ft.

THE STANDARD CIRCULATING SYSTEM OF DRILLING

In an effort to devise a means of drilling through unconsolidated sands and caving formations of the California San Joaquin Valley fields to depths of more than 3,000 ft. with cable tools, and to reduce the number of strings of casing necessary in so doing, the so-called "circulating system" of drilling was developed. This method involves the use of the complete standard cable equipment and, in addition, a pair of high-pressure slush pumps such as are used in rotary drilling, with flexible connections to a "circulating head" supported by a massive "swinging spider" on which the casing in the well is suspended (see Fig. 62). The purpose of the additional equipment is to provide a means of "mudding" the soft material in the walls of the well so that it does not cave about the

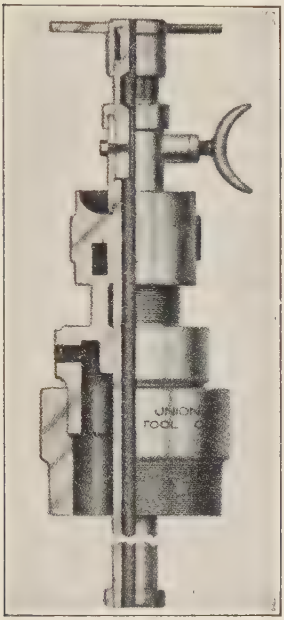
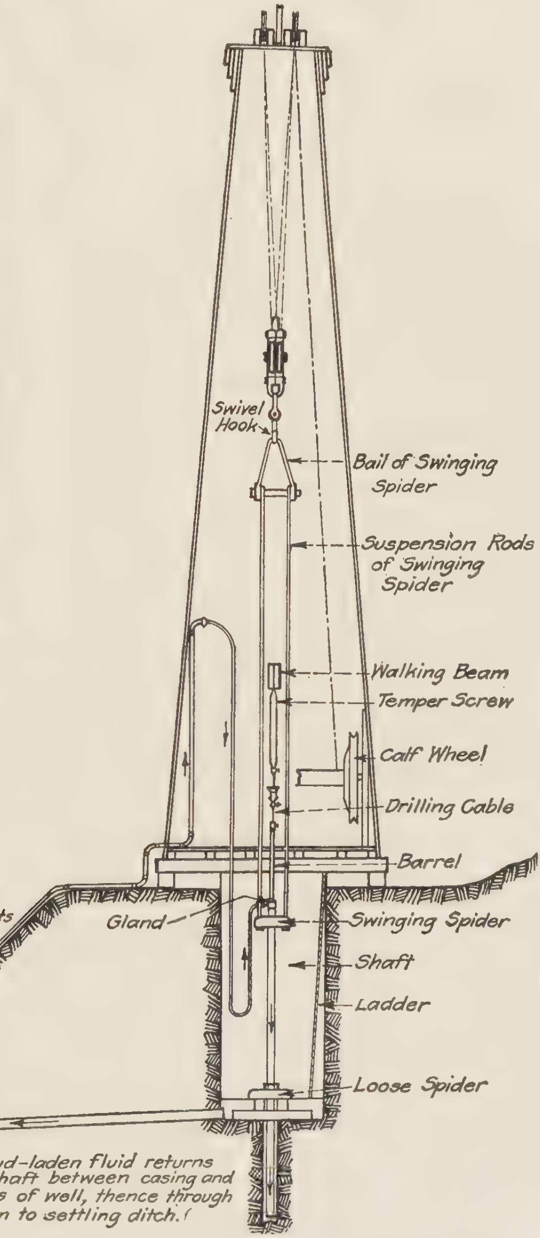


FIG. 63.—Circulating head.



(*After A. B. Thompson, with additions.*)

FIG. 62.—Sketch showing arrangement of equipment for standard circulating system of drilling.

casing, a process commonly employed in rotary drilling (see page 227). Mud-laden water is pumped down through the casing, passes under the casing shoe, which is lowered as the bit progresses, and back to the surface in the annular space between the casing and the walls of the well. In order to keep this space clear, the casing is frequently raised for a few feet and lowered with the swinging spider, which is supported by a large hook and hoisting block strung on the casing line from the derrick crown block. The circulating fluid, in addition to mudding the walls of the well so that they do not cave, serves to lift a part of the material loosened by the drill so that less bailing of the well is necessary.

The cable tools operate in the usual manner, except that the drilling cable works through a stuffing box in the circulating head, which prevents leakage of the mud-laden fluid as it is pumped down through the casing. The stuffing box is so designed that it does not seriously interfere with the lowering and withdrawal of the drilling tools (see Fig. 63). A polished plunger is fastened around the drilling cable by means of rope clamps, which on being released allow the cable to be drawn from the well through the circulating head until the rope socket emerges from the well. The bolts which fasten the stuffing box in the circulating head are then loosened and the entire top of the head with the polished plunger and stuffing box is lifted out with the tools, leaving the full cross section of the casing free for bailing or other operations. In lowering the tools into the well to resume drilling, the top of the circulating head is bolted in position as soon as the tools have entered the casing, but the plunger is not clamped to the cable until the tools have reached drilling position at the bottom of the well and have been hitched to the beam.

The temper screw plays between the two reins of the swinging spider, which are about 40 ft. long. The cellar should be about 30 ft. deep and of ample size to permit of proper manipulation of the swinging spider. At the cellar bottom a stationary casing spider is placed, which supports the pipe in the well when a new joint is added. The column of casing in the well is raised and lowered with the swinging spider at intervals of from 10 to 20 min. without interruption in drilling. The pumps connect with side openings in the circulating head through armored hose. Returns from the well flow through a trough in which the coarse sand settles, to a mud pit where the fluid is taken in by the pump suction lines for repeated circulation through the well.

It is important, when this system of drilling is used, to maintain ample clearance between the casing and the walls of the well, thus eliminating danger of sand lodging around the pipe and interfering with circulation of the well fluid or of freezing the working string of casing. An unusually heavy casing shoe is employed and all hard formations are underreamed until the casing can be lowered freely. Also, the casing used is somewhat smaller in diameter than the casing normally employed in a

hole of the size drilled. When a conductor pipe is landed, the clearance necessary to maintain circulation of the well without the application of abnormal pressure is obtained by skipping one size of pipe in the usual series of telescoping sizes; thus, a 10-in. casing may be used inside of a 15½-in. conductor string instead of a 12½-in. one. It is usually important to maintain fairly continuous operation of one or another of the two pumps. A shut down of more than an hour or so may result in settling of the mud, causing freezing of the casing or loss of circulation.

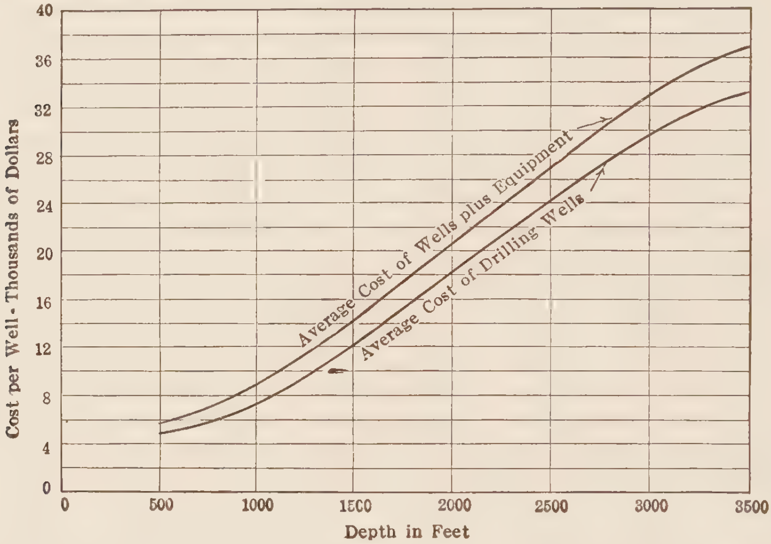
This method of drilling has been given a sufficient trial in the oil fields of California to prove definitely that it is practical and that it has certain advantages over the ordinary cable drilling method in drilling through unconsolidated caving formations. The most important advantage is that, by the use of it, strings of large-diameter pipe can be carried to unusual depths without danger of "freezing." This often results in the saving of one or more strings of casing and leaves a larger available working diameter in the bottom of the well. Better drilling time results from the absence of casing difficulties and because bailing is not so frequent an interruption. Through the use of the circulating mud-laden fluid, better control of high gas, oil and water pressures is afforded. While the additional equipment necessary is costly, the added expense is offset by the saving in casing and more rapid progress.

Notwithstanding the demonstrated advantages of this method of drilling, it is now rarely if ever used because the rotary method has been found cheaper and even better adapted to the conditions against which it was designed to contend. Nevertheless, it is not many years since a considerable number of wells were successfully drilled by this method, and the records made with it compare favorably, except for the greater cost, with those achieved by the more modern rotary equipment. In one well a 15½-in. string was set at 2,300 ft. and a 12½-in. string through this at 3,003 ft. In another well, the 15½-in. string was set at 2,100 ft. and a 10-in. string at 3,300 ft. In each case the casing was entirely free in the well, though previous drilling in the same territory by ordinary standard cable methods had shown that the walls could not be maintained for more than 40 or 50 ft. ahead of the pipe.[4]

COST OF CABLE DRILLING

The cost of drilling with cable tools varies widely in different regions, being dependent to an important extent upon accessibility, depth and character of the formations to be penetrated, prevailing wage scales and other related factors. Fluctuation in the purchasing power of the dollar during the last 20 years has also been responsible for wide variation in drilling costs. Within recent years, contracts have been let for the drilling of wells to depths of less than 1,500 ft. through the hard formations overlying the oil sands in the northern Pennsylvania region for

less than $1 per foot. These wells were drilled with semiportable rigs such as that illustrated in Fig. 61, and the contractor furnished everything necessary for the drilling of the well except casing and the gas used



(*After M. L. Requa.*)

FIG. 64.—Graphs showing average cost of drilling and equipping oil wells, San Joaquin Valley fields, California, 1914.

in developing power. Contract prices for cable-drilled wells in the Texas and California fields, on the same basis, using Standard rigs, have been in many cases in excess of $5 per foot. For deeper drilling by cable methods in western American fields post-war costs have been as high as $10 per foot in some instances.

COMPARATIVE UNIT DRILLING COSTS, 1913 TO 1920, CALIFORNIA FIELDS

Standard Cable Drilling Costs.—Cost in dollars per foot for 6 different properties operated by a large company in the Sunset (California) field. Average depth wells about 2,000 ft.

Property No.	Year							
	1913	1914	1915	1916	1917	1918	1919	1920
1	10.84	11.13	11.46	13.04	15.48	17.52	18.35	19.25
2	9.85	10.29	10.75	12.25	14.68	16.89	17.72	18.64
3	10.36	10.65	10.96	12.47	14.80	16.75	17.55	18.41
4	11.40	11.80	12.19	14.02	16.69	19.03	19.96	20.86
5	10.68	11.15	11.65	13.28	15.91	18.31	19.21	20.20
6	10.44	10.81	11.17	12.84	15.29	17.43	18.28	19.11

Figure 64 indicates the average cost of drilling to various depths for a group of wells drilled chiefly with cable tools in the San Joaquin Valley fields of California prior to 1914. The lower of the two graphs represents the bare cost of drilling and permanent well equipment, while the upper

TABLE XVIII.—COST OF DRILLING FOUR WELLS, COALINGA FIELD, STANDARD TOOLS, 1913*

	Depth of well			
	1,330 ft.	2,083 ft.	2,485 ft.	2,830 ft.
Derrick and rig:				
Labor, grading	$ 20.00	$ 15.65	$ 8.90	$ 20.00
Lumber, nails, bolts, etc.	1,126.00	1,303.21	1,421.34	1,593.64
Rig irons	495.42	495.42	495.42	690.00
Teaming	137.75	72.20	66.38	150.00
Planing mill, material and labor (oak arms, cants, etc.)	85.50	84.55	111.60	126.25
Machine shop work on bolts and rods	1.80	2.75	7.60	12.50
Labor, building rig, including placing rig irons	265.00	265.00	295.00	250.00
Total, derrick and rig	$ 2,131.47	$ 2,238.78	$ 2,406.24	$ 2,842.39
Rigging up:				
General supplies, including lumber, line pipe, engine and boiler fittings, brick, lime, and sundry fittings	$ 678.71	$ 537.90	$ 533.43	$ 743.34
Teaming	87.90	61.00	87.67	100.00
Shop work	12.75	11.75	22.40	66.00
Labor	566.20	605.63	587.66	594.30
Total, rigging up	$ 1,345.56	$ 1,216.28	$ 1,231.16	$ 1,503.64
Engines and boilers:				
Maintenance covered by general drilling expenses charged below.				
Removed on completion of well, and replaced by gas engine as below.				
Drilling:				
Belts	$ 87.73	$ 175.46	$ 228.27	$ 159.29
Bull ropes	44.20	65.50	69.30	63.68
Casing	5,316.73	8,562.50	10,481.10	13,567.84
General supplies	660.25	1,439.61	1,205.23	1,443.93
Machine shop work	142.45	363.95	318.60	447.55
Teaming	189.47	320.98	268.12	569.85
Labor (including installing tubing and pumps)	2,081.30	4,244.77	3,987.45	3,748.80
General drilling expense, including drilling lines, upkeep of tools, proportion of drilling, superintendent's salary, etc.	1,820.00	3,600.00	3,000.00	3,640.00
Total cost of drilling	$10,342.13	$18,772.77	$19,558.07	$23,640.94
Fuel:				
Natural gas used (no cost)				
Water	$ 120.00	$ 120.00	$ 180.00	$ 180.00
Gas engine:				
One 25 hp	665.00	665.00	665.00	665.00
Labor, installing and fitting	66.71	66.71	88.30	88.30
Total fuel	$ 731.71	$ 731.71	$ 753.30	$ 753.30
Labor:				
Removing steam engine and boilers	$ 20.00	$ 20.00	$ 20.00	$ 20.00
Tubing	400.30	400.30	799.20	799.20
Rods	122.40	122.40	243.00	243.00
Pumps	20.22	20.22	24.51	24.51
Tankage	327.50	327.50	327.50	327.50
Grand total	$15,561.29	$23,969.96	$25,542.98	$30,334.48
Total cost per foot	$ 11.70	$ 11.49	$ 10.28	$ 11.08
Actual working time (days)	80	160	149	175
Feet per day	16.6	13.0	16.7	16.2

* After R. P. McLaughlin, Calif. State Mining Bur., *Bull.* 69.

graph includes additional tankage, gathering lines, electrical equipment, etc.

The table on page 188 shows how the cost of cable-drilled wells in a California field increased during the war and immediate post-war periods

TABLE XIX.—COST OF DRILLING WELLS WITH CABLE TOOLS

	Well No. 1		Well No. 2		Well No. 3		Well No. 4		Well No. 5		Well No. 6	
Field	Ranger, Tex.		Desdamona, Tex.		Caddo, La.		Lost Hills, Cal.		Coalinga, Cal.		Sunset, Cal.	
Year drilled	1919		1919		1919		1920		1920		1920	
Depth in feet	3,200		2,700		3,200		1,418		1,650		1,200	
Drilling time, days	60		50		60		79		100		50	
	Total	Per ft.	Total	Per ft.	Total	Per ft.	Total	Per ft.	Total	Per ft.	Total	Per ft.
Derrick and rig	$ 4,500	$ 1.41	$ 4,800	$ 1.78	$ 5,000	$ 1.56	$ 4,750	$ 3.35	$ 5,000	$ 3.03	$ 4,326	$ 3.61
Engine and boilers	†	†	†	†	†	†	695	.49	660	.40	275	.23
Tanks, sumps and flow lines	3,000	.94	3,000	1.11	3,000	.94	*	*	*	*	*	*
Fuel and water	1,200	.38	1,150	.43	1,400	.44	908	.64	2,277	1.38	450	.37
Drilling	13,450	4.20	13,050	4.84	16,500	5.15	3,106	2.19	4,191	2.54	2,475	2.06
Casing	16,476	5.14	13,899	5.14	16,720	5.23	10,663	7.52	13,695	8.30	4,867	4.06
Cementing	....	......	....	......	....	......	780	.55	412	.25	375	.31
Shooting	920	.29	920	.34	920	.29						
Hauling	1,000	.31	1,150	.43	3,400	1.06	950	.67	743	.45	275	.23
Overhead and incidental expense	4,055	1.27	3,842	1.42	4,704	1.47	893	.63	1,419	.86	1,064	.89
Totals	$44,601	$13.94	$41,811	$15.49	$51,644	$16.14	$22,745	$16.04	$28,397	$17.21	$14,107	$11.76

Well No. 1: 82- by 22-ft. derrick; 6-in. rig irons; gas fuel; 350 ft. of 15½-in., 70-lb. casing; 800 ft. of 12½-in., 50-lb. casing; 1,400 ft. of 10-in., 40-lb. casing; 2,000 ft. of 8¼-in., 32 lb. casing; and 3,200 ft. of 6⅝-in., 24-lb. casing; 200 ft. of hard black lime requiring underreaming; 200-qt. shot of nitroglycerin. Contract drilling at $3 per foot; black lime, $10 per foot.

Well No. 2: 82- by 22-ft. derrick; 6-in. rig irons; gas fuel; 800 ft. of 12½-in., 50-lb. casing; 1,400 ft. of 10-in., 40-lb. casing; 2,000 ft. of 8¼-in., 32-lb. casing; 2,700 ft. of 6⅝-in., 24-lb. casing; 150 ft. hard lime; 200-qt. shot of nitroglycerin. Contract drilling at $4 per foot; black lime, $10 per foot.

Well No. 3: 82- by 22-ft. derrick; 6-in. rig irons; gas fuel; 350 ft. of 15½-in., 70-lb. casing; 800 ft. of 12½-in., 50-lb. casing; 1,400 ft. of 10-in., 40-lb. casing; 2,200 ft. of 8¼-in., 32-lb. casing; and 3,100 ft. of 6⅝-in., 24-lb. casing. Contract drilling at $4.50 per foot.

Well No. 4: 82- by 22-ft. derrick; oil fuel; 530 ft. of 13½-in. stove pipe; 950 ft. of 10-in., 40-lb. casing; 1,250 ft. of 8¼-in., 28-lb. casing; 1,418 ft. of 6¼-in., 20-lb. casing. Long haul of materials. Soft shales and sandstones. Drilling cost is chiefly labor.

Well No. 5: 82- by 22-ft. derrick; oil fuel; 500 ft. of 12½-in., 40-lb. casing; 1,000 ft. of 10-in., 40-lb. casing; 1,575 ft. of 8¼-in., 28-lb. casing; and 1,650 ft. of 6¼-in., 20-lb. casing. Long haul of materials. Soft shales and sandstones. Drilling cost is chiefly labor.

Well No. 6: 74- by 20-ft. derrick; gas fuel; 806 ft. of 10-in. casing; 1,176 ft. of 8¼-in. casing. Steam furnished from boiler plant already in operation. Short haul of materials. Soft shales and sandstones. Drilling cost is chiefly labor.

Costs given for Wells 1, 2 and 3 are estimates, after J. R. Suman; those given for Wells 4, 5 and 6 are actual costs.

* Not included.

† Included with rig and derrick.

Table XVIII presents detailed data showing the cost of drilling in a certain California field just prior to the war. Table XIX shows post-war cable-drilling costs in several western American fields.*

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See also references 1 to 12 at end of Chap. V.

* For additional information on drilling costs, see pp. 268 to 272.

CHAPTER VII

ROTARY DRILLING EQUIPMENT AND METHODS

The general features of the hydraulic rotary system of drilling were outlined in Chap. V. There, also, details of construction and design of derricks for rotary drilling were discussed. In the present chapter we are to be concerned with additional description of equipment and methods relating to the rotary systems of drilling. As pointed out at the beginning of Chap. V, there are at least three fundamentally different types of rotary equipment. We shall devote most of our available space to the mechanically controlled type chiefly used in the petroleum industry up to the present time. The hydraulic systems of control have as yet attained only comparatively limited use and hence will be described but briefly.

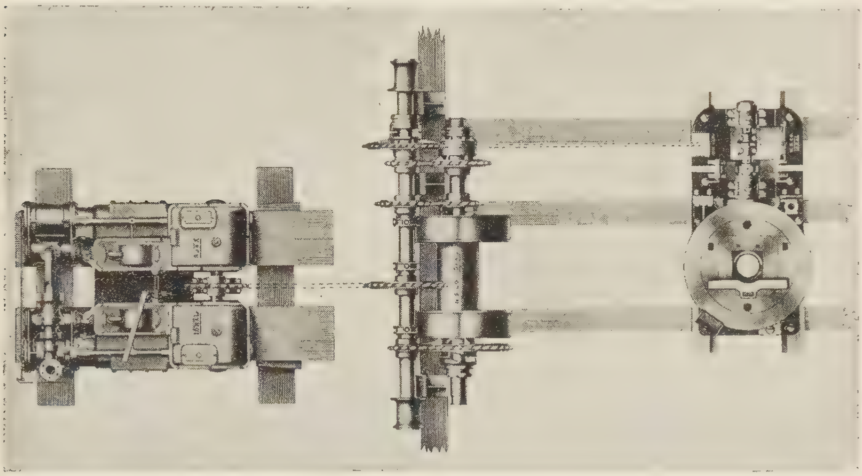
MECHANICALLY CONTROLLED HYDRAULIC ROTARY EQUIPMENT

The Draw Works.—The draw works serves as a power-distribution center for all power-driven parts of the rig except the pumps. It consists of two principal parts: (1) the hoisting drum with its shaft, supporting boxes, sprockets, clutches and brakes; and (2) the drive shaft with its supports, several sprockets and clutches and two "catheads." In some patterns of multispeed draw works, an auxiliary countershaft with incidental bearings, clutches and sprockets is provided as an integral part of the draw works. The component parts are mounted on opposite sides of supporting posts, two or three in number, sometimes of timber, though in heavier rigs often of steel. Figure 65 shows in plan view the relative positions of the drilling engine, draw works and rotary table.

Draw works are available from different manufacturers in a variety of styles, sizes and weights, designed for two, three, four or six hoisting speeds. Shallow drilling may be satisfactorily conducted with the mechanically simpler and less expensive two-speed draw works, but the heavier loads imposed in deeper drilling require the greater flexibility in speed and power control afforded by the four- or six-speed types.

Figure 66 is illustrative of one of the lighter types of two-speed draw works now used only in drilling comparatively shallow holes, say to depths of 3,000 ft. or less. With reference to Fig. 66, *A* is the sprocket which receives the power by chain drive from the engine. *B* and *C* are sprockets connected by a chain belt, which, when connected with the hoisting drum through clutch *D*, revolve it at the lower of its two speeds. Sprockets *E* and *F* and clutch *G* give the hoisting drum its high speed. These clutches, operated by lever *H*, are so spaced that as one is thrown out of gear,

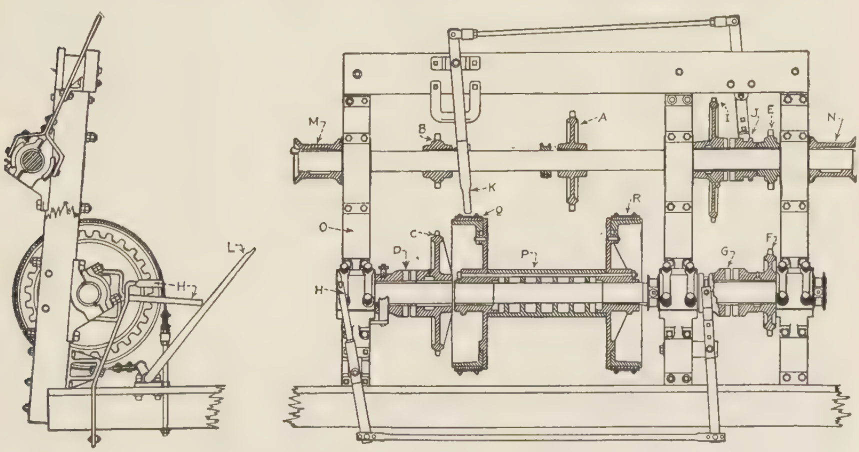
the other is thrown in, with a neutral position between, in which the hoisting drum is disconnected from the power. Sprocket *I* drives the rotary table and is thrown in and out of gear by clutch *J*, which is controlled by lever *K*. Brake lever *L* controls



(*Courtesy of National Supply Co. of California.*)

FIG. 65.—Plan view of rotary drilling equipment showing twin-cylinder steam engine, three-speed draw works and chain-driven rotary table.

the movement of the hoisting drum when it is under tension from the weight of the drill stem and the power clutches are disengaged. *M* and *N* are catheads useful in applying power to various small objects within the derrick, particularly to the



(*Redrawn with additions, from Union Tool Co.'s descriptive booklet.*)

FIG. 66.—Two-speed rotary draw works.

wrenches used in setting up the tool joints on the drill stem. The driller stands at post *O*, within easy reach of the brake and clutch levers. A "telegraph wheel" also on this post, with an endless wire strand to the throttle valve of the engine, gives convenient control of the power. Another sprocket is occasionally placed on the drive

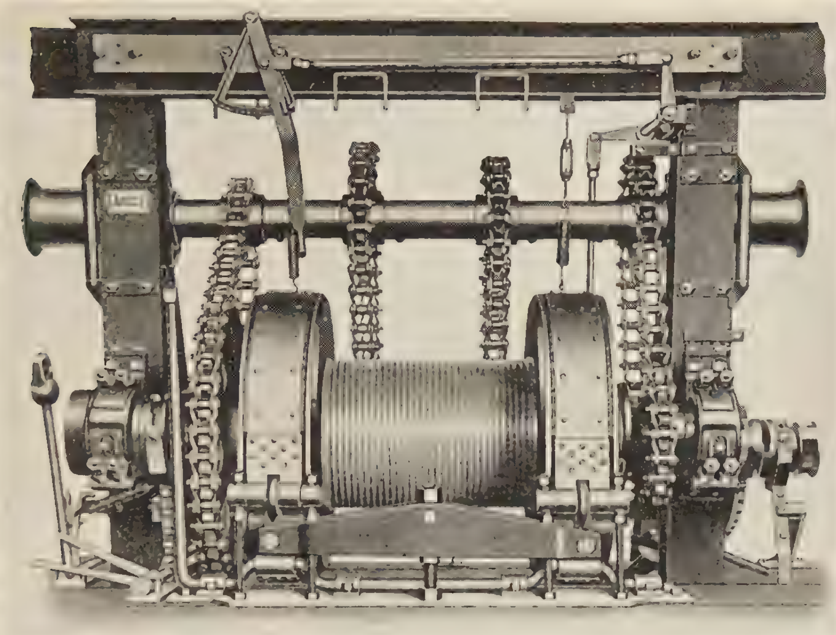
shaft to operate a mechanical mud mixer, though this device is not ordinarily a part of the rotary equipment.

The gear ratios on the sprockets driving the hoisting drum are 12 to 28 for the low-speed drive and 12 to 20 for the high-speed drive. Hence the faster of the two hoisting speeds is 1.4 times that of the lower. The actual speed in either case, of course, depends upon the speed of the engine, which is variable within wide limits. Some models are equipped with an additional pair of gears and clutch for a third speed, useful particularly in drawing out the drill stem. The drum P, on which the hoisting cable is wound, is about 16 in. in diameter and has flanges ranging between 34 and 42 in. in diameter, which provide braking surfaces for two powerful band brakes Q and R, each about 8 in. wide and lagged with hardwood or asbestos blocks. The brakes are controlled by lever L, which may be clamped to lock the brakes, with a chain attached to the derrick floor. An automatic spring suspension device prevents dragging of the brake bands on the drum flanges when the brake lever is released.

The weight of the hoisting drum with its shaft, clutches, sprockets, brakes and boxes varies from about 2,500 lb. for the lighter rigs to as much as 7,200 lb. in the larger sizes. The line shaft with its equipment weighs about 1,600 lb. The larger sizes of draw works of this type are designed to meet all the requirements imposed in handling drill stem and casing to a depth of 5,000 ft. For handling heavy casing at greater depths than this, or even at lesser depths when a light draw works is in use, a calf wheel is sometimes provided, similar to that used with the standard cable rig and operated by a chain drive from the line shaft or by a separate engine.

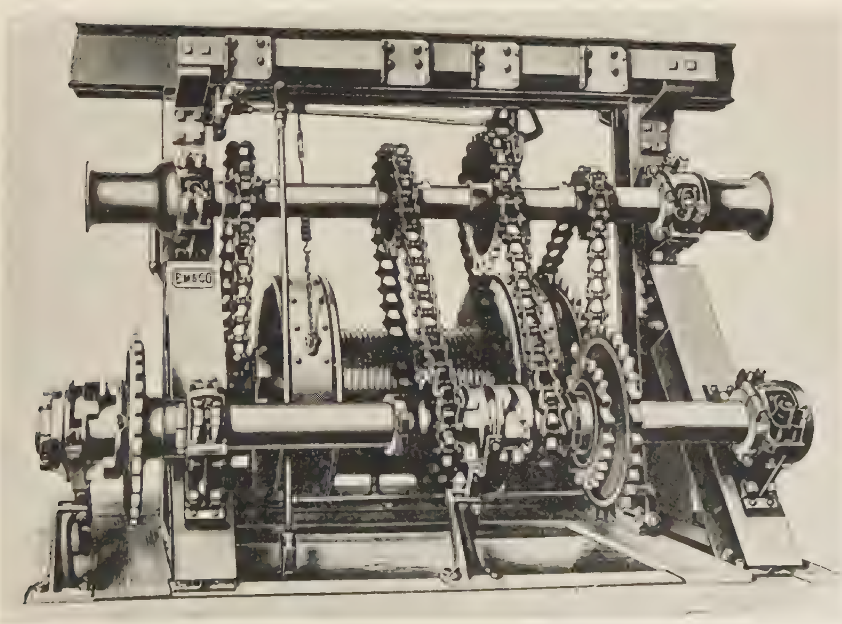
Occasionally, also, a bailing drum is attached to the hoisting drum shaft, with a separate clutch and brake. This is useful in bailing mud out of the well on its completion, or when testing oil or gas sands for production, and is also an advantage in certain fishing operations. If a "combination rig" is used (see page 121), bailing facilities and a calf wheel will be provided as a part of the cable-tool equipment.

Four or six hoisting speeds are possible through the use of an auxiliary countershaft. Figure 67 is a front view and Fig. 68 a rear view of a modern three-shaft, four-speed draw works of the type used in drilling to depths of 5,000 to 10,000 ft. Figures 69*A* and 69*B* present drawings of the same mechanism in front and end elevation. A double sprocket on the jackshaft receives the power from a double sprocket on the engine drive shaft. By changing the drive chain from one pair to the other of these sprockets two different speeds are possible for the jackshaft with constant engine speed. From the jackshaft there are two separate drives controlled by a clutch affording two different line-shaft speeds. There are also two different chain-and-sprocket drives from the line shaft to the hoisting-drum shaft, each providing a different hoisting-drum speed. The choice of either of two separate drives of different speed from the jackshaft to the line shaft, in combination with either of two separate drives of different speed from the line shaft to the hoisting-drum shaft, permits a choice of any of four different hoisting speeds for a given engine speed. Still greater speed variation is secured by shifting the drive chain from one to the other of the two pairs of sprockets on the engine drive, and there is, of course, a wide range of possible speeds for the engine drive shaft by varying the steam supply. A sprocket, controlled by a clutch, on one end of the jackshaft, carries the chain which drives the rotary table. The line shaft and hoisting drum are supported on opposite sides of two steel H-beam posts, braced by short H-posts which support the jackshaft. Each shaft is supported by two roller bearings. The hoisting drum is 25 in. in diameter and its surface is grooved to facilitate spooling of the hoisting cable. The hoisting-drum brake flanges are 54 in. in diameter. Both the hoisting drum and its flanges are of special design to resist collapse under extreme hoisting-line tension. The heavy band brakes, with woven block lining, are equipped with spring suspension and a



(*Emsco Derrick and Equipment Co.*)

FIG. 67.—Three-shaft, four-speed draw works, front view.



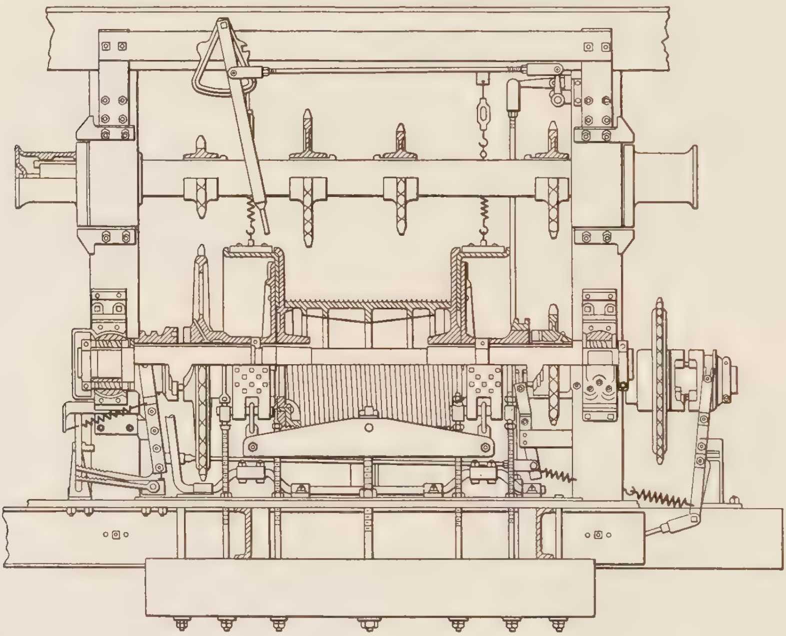
(*Emsco Derrick and Equipment Co.*)

FIG. 68.—Three-shaft, four-speed draw works, rear view.

beam-equalizer mechanism to assure smooth braking action. The various clutches and brakes are controlled by a system of levers and pedals centered about the driller's position at the control post. Four-speed draw works of this type may weigh as much as 20,000 lb.

The four-speed draw works illustrated and described above, when used in conjunction with the Hild or Halliburton differential drives—to be described in a later section—provides six different clutch-controlled speeds.

The Rotary Table.—The rotary table, which revolves the drill pipe, is operated by a chain drive from the draw works. Except in the shaft-drive type of rotary table described below, the power is transmitted directly from a sprocket on the line shaft (in the case of a three-shaft draw works, from the jackshaft) of the draw works to a second sprocket on a short pinion shaft mounted in a horizontal position at one side



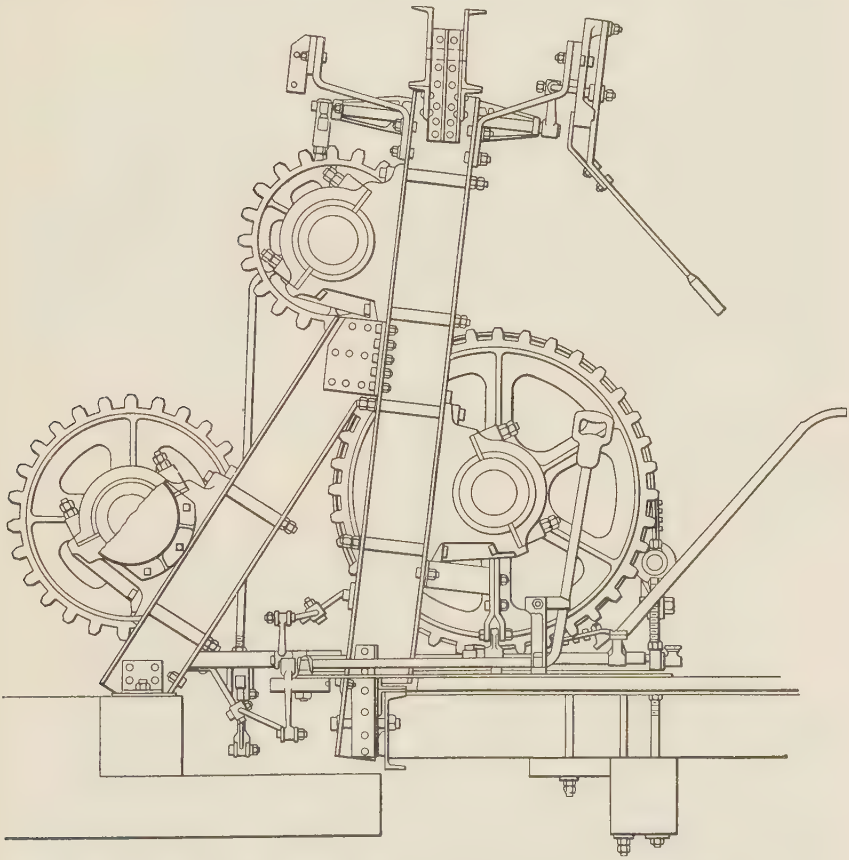
(Redrawn from an original drawing furnished through the courtesy of Emsco Derrick and Equipment Co.)
FIG. 69A.—Front elevation of three-shaft, four-speed draw works.

of the rotary table. The pinion shaft is supported by two bearings, and on one end of it there is keyed a beveled pinion which meshes with a circular beveled gear on the lower side of the table (see Fig. 70). In some cases the pinion shaft also supports a clutch, which permits of disengaging the power at the table, but more frequently a clutch controlling the drive sprocket on the draw-works line shaft or jackshaft is depended upon for this purpose. A ratchet locking device on the pinion shaft prevents the table from revolving when screwing or unscrewing the drill pipe. A special reduction gear unit, which may be attached to the table jackshaft, provides two table speeds, one approximately twice the other, with but a single drive from the draw works. A conveniently located lever on the gear unit permits of rapidly changing from one speed to the other as desired.

The above described arrangement of the power connections necessitates the use of a long drive chain, extending nearly halfway across the free space within the derrick. Because of its exposed location, its high operating speed, the variable and often extreme

strain imposed upon it and its susceptibility to breakage, this chain is a menace to the men at work on the derrick floor unless protected by adequate steel guards or housing (see Fig. 71). It is furthermore an obstruction that prevents free passage about the rotary table.

In order to avoid the use of this long drive chain, a type of shaft-driven rotary table has been developed which is preferred by some operators. In this, the pinion shaft of the table is placed at right angles to its usual position and is extended across



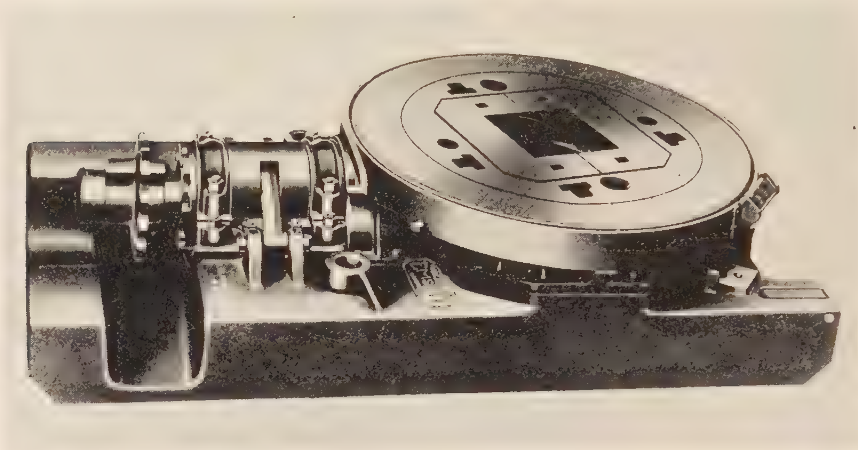
(Redrawn from an original drawing furnished through the courtesy of Emsco Derrick and Equipment Co.)

FIG. 69*B*.—Side elevation of three-shaft, four-speed draw works.

the derrick floor and under the hoisting drum to a gear base located between the draw works and the engine (see Fig. 72). The gear base contains two beveled pinions which permit of revolving the drive shaft by a short pinion shaft, mounted parallel with the line shaft of the draw works. A pair of sprockets on the two latter shafts, and a chain belt, provide the necessary power connection (see Fig. 73).

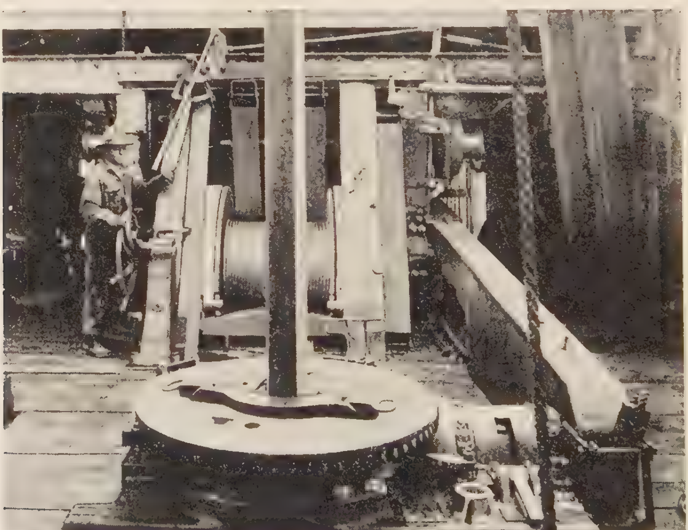
The rotary table (see Fig. 74) consists of a heavy steel casting *A* about 4 ft. in diameter, with a smooth, flat top and with beveled gearing *B*, cast into the lower side or secured rigidly thereto. There is also cast into the lower portion of the table, a groove *C*, which serves as a raceway for ball or cone roller bearings on which the table revolves. The cones or balls, mounted in a circular groove in the metal base *E*

revolve in a bath of oil automatically fed from an oil reservoir. The grooves in both the rotary table and the table base are fitted with renewable flanged race plates *F* of high-grade carbon or alloy steel, which furnish a housing for the bearings and prevent



(Courtesy of Emsco Derrick and Equipment Co.)
FIG. 70.—Rotary table.

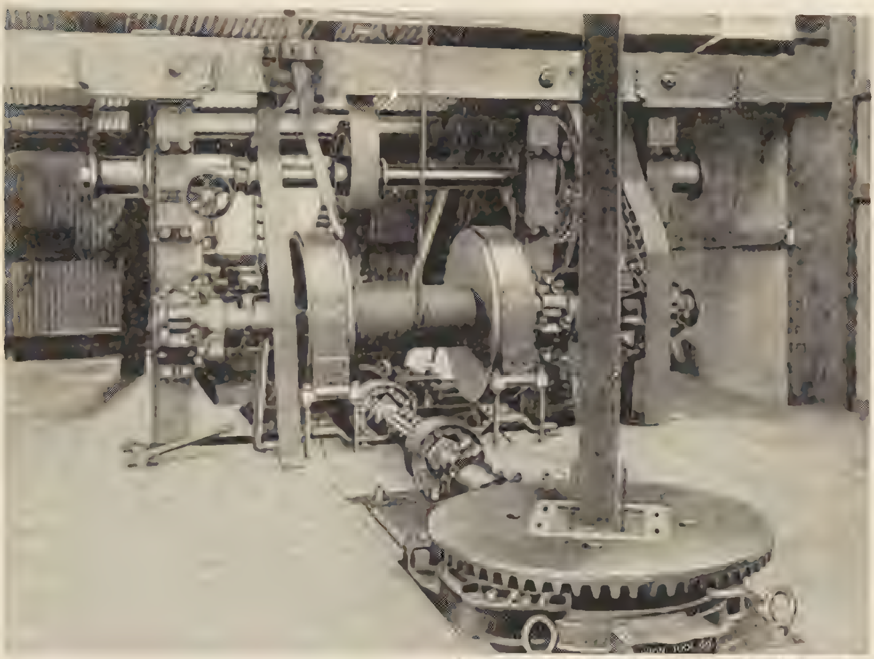
wear on the heavier castings. The support for the pinion shaft is a separate casting, equipped with roller bearings and securely bolted to the table base. To prevent the



(Courtesy of Emsco Derrick and Equipment Co.)
FIG. 71.—Rotary table and draw works.

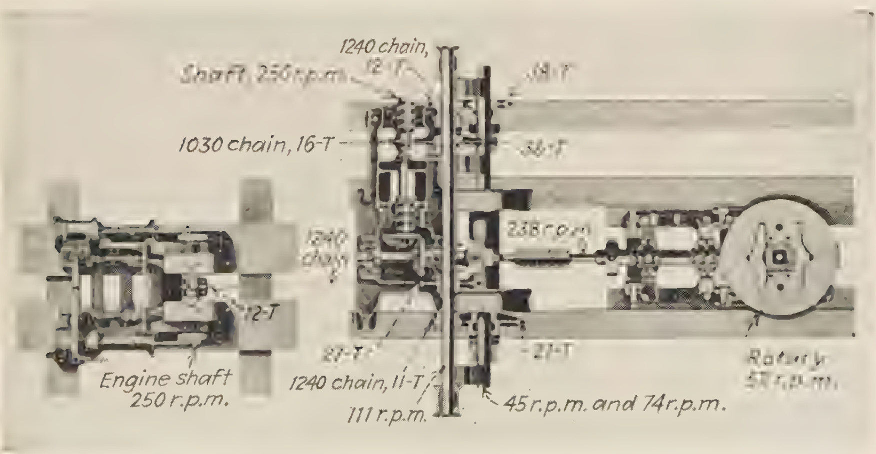
table from being lifted from its supports by the pinion when under strain, a hold-down ring or hold-down brackets *G* are provided, which are bolted to the table base and project over a machined circular projection on the lower edge of the table. In some

heavy models this bearing is also equipped with balls or cones to resist friction. The metal base is bolted to a substantial timber or steel frame which rests on sills below



(Courtesy of National Supply Co. of California.)

Fig. 72.—Shaft-driven rotary table showing three-speed draw works.



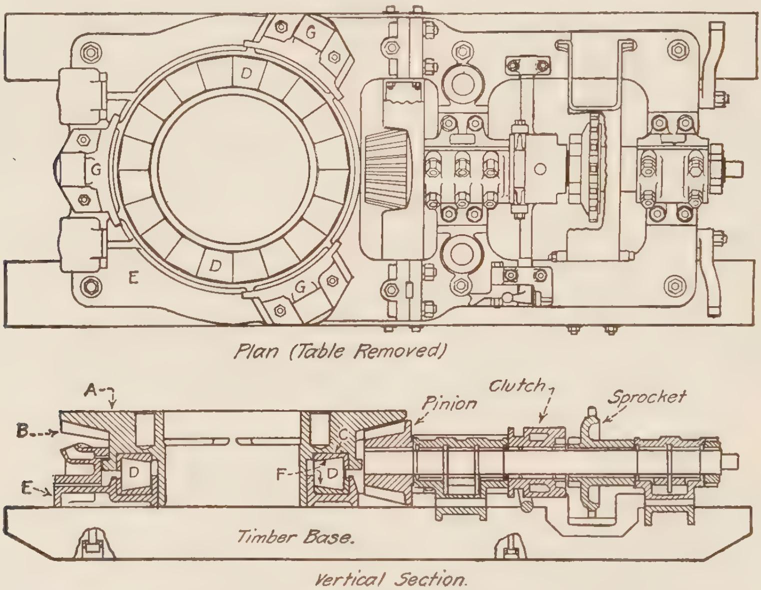
(Courtesy of National Supply Co. of California.)

Fig. 73.—Plan view of shaft-driven rotary equipment showing arrangement of twin-cylinder steam engine, gear unit, draw works and rotary table.

the derrick floor. Substantial steel housing completely encloses the moving parts below the table top.

Through the center of the table an opening is provided for passage of the drill stem. The form of this opening varies with the type of gripping device and table bushings adopted. A common type of table gripping device, utilizing the square grief stem or "kelly," has an opening which is square at the top and conical or cylindrical toward the bottom (see Fig. 70). It is equipped with a split bushing similar in form, which has a conical opening through its center. This conical opening is designed to support either a split bushing of a size and shape to fit the square grief stem or a set of "slips" for gripping the cylindrical drill pipe.

So called "make-and-break" rotary tables are also provided with facilities designed to assist in coupling and uncoupling drill pipe and casing. A gripping device built or fitted into the table base supports the casing below the collar or tool joint to be worked on. The table is then free to turn without the pipe. A post supported in a vertical



(Redrawn with additions, from Union Tool Co's. descriptive pamphlet.)
FIG. 74.—Chain-driven rotary table

position in the table top bears against the handle of the pipe tongs attached to the pipe above the joint, and thus the joint may be "made up" or "broken out" by rotating the table with the power.

Rotary tables are rated by the diameter of the opening through the table and vary from 19 to 27½ in. The size of this opening is frequently also a measure of the maximum diameter of drilling bit that can be passed through the table and hence determines the maximum diameter of hole that can be drilled. In some models, however, rectangular, slot-shaped extensions of the table opening permit of passing a fishtail bit of slightly larger width than the diameter of the cylindrical portion of the table opening. A 20-in. rotary table and pinion shaft, complete with all its parts, weighs approximately 6,500 lb. The 27½-in. table may weigh as much as 10,000 lb.

Rotary Chain Belt.—The sprocket chains that are used for transmitting power between the various parts of the rotary drilling rig are of substantial construction and so designed that the chain may be readily broken or disengaged at any link. This is necessary in order to facilitate repairs or to adjust tension, or—in the case of the chain

to the rotary table sprocket—to get it out of the way of operations on the derrick floor when it is not needed.

The links are available in several different styles or patterns, usually made of steel, though frequently of malleable iron. In one type of chain that is commonly used the links are made of two separate side bars fastened together at the joints with bushings or barrels and either rivets, bolts, pins or cotters. The bushings or barrels at the joints take up most of the wear and are easily replaceable. Another type is made of malleable iron, each link being cast separately in one piece, and the links later coupled together to form the chain.

These chains must be operated with considerable slack over the sprockets, otherwise they bind, make considerable noise and power is wasted in unnecessary friction. To reduce friction, noise and wear on the links and sprockets, the chains must be occasionally greased.

Grief Stems.—In order that the rotary table may have a positive grip on the drill stem, the first 28 or 45 ft. below the swivel consists of a specially designed "grief stem" or "kelly joint" of angular form designed to fit a similarly shaped opening in the rotary table. The grief stem is usually square in cross section (see Fig. 71), though hexagonal and cruciform shapes have also been used. A cylindrical hole is provided through the grief stem for the passage of the circulating fluid, and there is a pipe thread joint at each end for connecting by means of suitable collars with the cylindrical drill pipe and the rotary swivel.

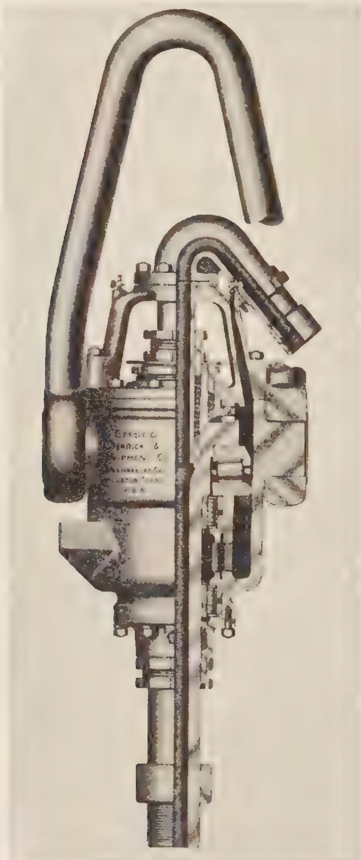
Earlier models of rotary tables were equipped with a gripping device for the cylindrical drill pipe so that the use of a special grief stem was unnecessary. The gripping device consisted of two pair of steel rollers so mounted in sliding blocks controlled by heavy screws that their corners could be clamped against the pipe. While this type of gripping device served its intended purpose, the corners of the rollers scored the pipe heavily, weakening it to some extent, and the screws controlling the position of the rollers required frequent tightening. It is still used to a limited extent, particularly in handling the smaller sizes of drill stem and in rotating casing.

The rotary swivel, which provides a means of pumping the circulating fluid into the rotating drill stem, and from which the latter is suspended while in the well, is illustrated in Fig. 75. It consists of a number of parts, all of which are contained within, or supported by, a massive trunnion and bail. The upper portion of the trunnion block contains a gooseneck, to which the armored hose leading from the pumps is connected. The heavy tubing connecting with the drill stem turns with the latter, a collar being provided on the upper end of it, which rests on roller bearings to reduce friction. A ball bearing is also provided between the revolving and stationary portions of the swivel to take up the thrust that may at times cause considerable pressure between the two parts. Several stuffing boxes are provided to prevent leakage, and there is an elaborate lubricating system which keeps the moving parts and friction surfaces within the swivel immersed in oil. When properly assembled and lubricated, there is practically no leakage of either water or oil from the swivel, and the lower portion attached to the top of the drill pipe turns freely and yet without any appreciable tendency to twist the cables of the hoisting block on which it is suspended. A complete swivel for a 6-in. drill pipe will normally weigh about 2,150 lb.

The swivel must at times support the full weight of the drill pipe, and, inasmuch as this may impose a load of many tons, the supporting elements must be of massive construction. The gudgeons on heavier models are of solid steel 5½ in. in diameter, and the bail is often 4½ in. in diameter. Swivels used in deep drilling are in some instances designed for a safe working load of 300,000 lb.

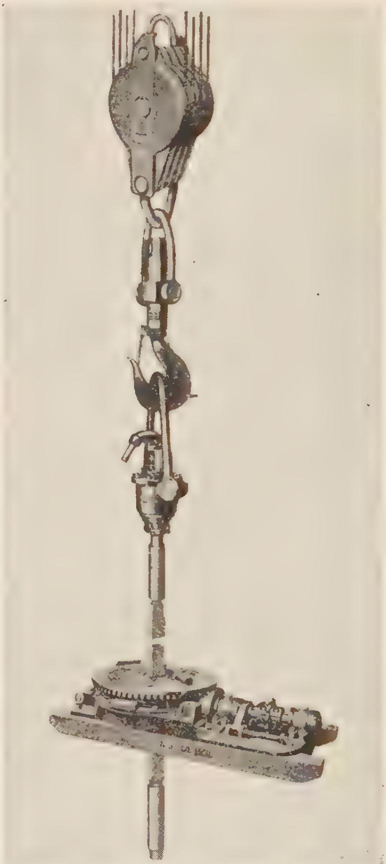
The Hoisting Block and Hook (see Fig. 76).—The hoisting block serves the double function of handling drill pipe and running casing into the well. It may contain from

three to six sheaves, depending upon the loads to be handled and the mechanical advantage necessary. A five-sheave block, commonly used, permits of stringing as many as 11 lines between it and the crown block. This provides a mechanical advantage of 10 in favor of the draw-works hoisting drum on which the free end of the cable is wound. For handling exceptionally long columns of heavy casing, six-sheave blocks are used, affording 12 or 13 lines, depending upon the method of stringing. For



(Courtesy of Emsco Derrick and Equipment Co.)

FIG. 75.—Rotary swivel.



(Courtesy of National Supply Co. of California.)

FIG. 76.—Hoisting block, hook, swivel, grief stem and rotary table in working position.

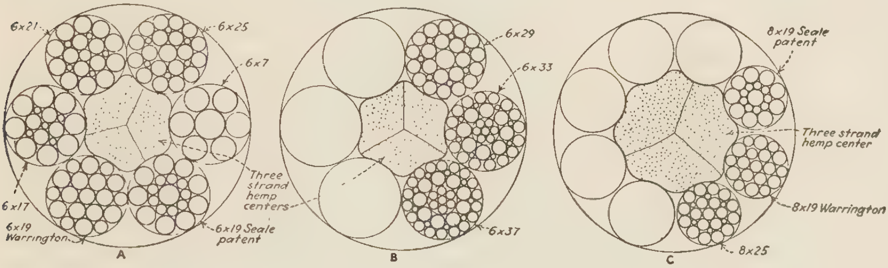
most purposes, however, where lighter service is required, a smaller number of lines with correspondingly greater hoisting speed will be preferred.

A large hook suspended from the lower bail of the hoisting block engages the bail of the rotary swivel or the links of the casing or drill-pipe elevators. The hook is supported on a heavy spring, designed to relieve the hoisting equipment of sudden impact loads. A safety latch prevents the bail of the swivel or the elevator links from slipping off the hook when lines are slackened or when the drill pipe is subjected to excessive vibration. The hook must be suspended well below the center of gravity

of the hoisting block, otherwise there is a tendency for the block to turn over when subjected to heavy loads (see also Fig. 123*C*).

To prevent rapid wear of the hoisting cable, the sheaves of the hoisting block should be of large diameter. Heavier blocks available on the market use sheaves 30 or 36 in. in diameter. They are often constructed of manganese steel to reduce wear, and the grooves are preferably shaped to conform with specifications adopted by the American Petroleum Institute. Roller bearings on the sheave trunnions reduce friction. The sheaves should be enclosed by suitable guards or housing to reduce as far as possible the danger of workers being caught between the rope and the sheaves and to prevent the hoisting cable from slipping off the sheaves.

The size of a traveling block is designated by the distance between the top and bottom bracket pins, 54- and 66-in. blocks being commonly used. A 66-in., five-sheave traveling block may weigh as much as 6,200 lb. and has a rated safe working load as high as 250 tons.



(*After A. S. Rairden in Oil and Gas Journal.*)

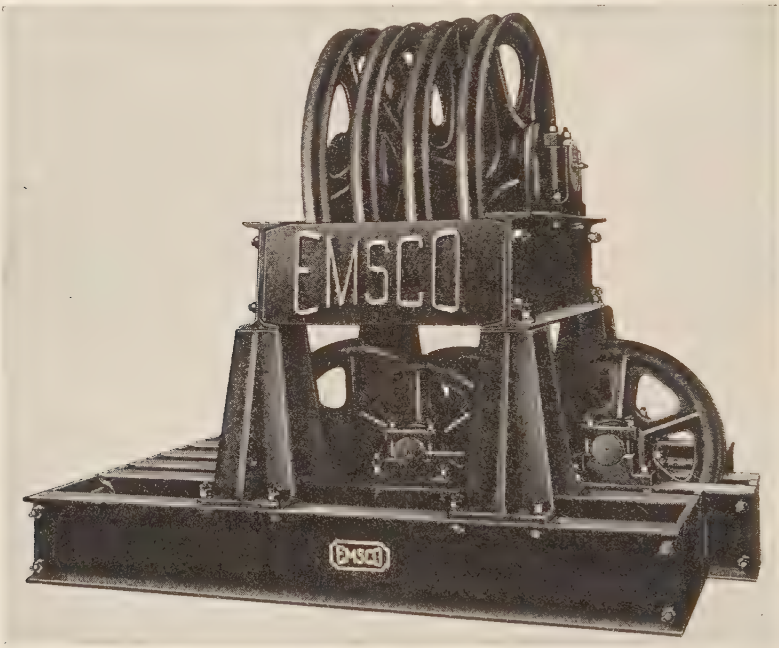
Fig. 77.—Cross sections of various styles of hoisting cable.

The Hoisting Cable.—The hoisting cable of the rotary rig must at times support the full weight of the drill stem, swivel, hook and hoisting block—a load which may total as much as 150 tons in deep wells. It is furthermore subjected to considerable wear and stress in its repeated travel over the sheaves in the crown block and hoisting block. It must therefore be of appropriate size and of suitable material to resist the strain and wear imposed. Steel-wire cables ranging in diameter from $\frac{7}{8}$ to $1\frac{1}{8}$ in. are used for this purpose, the size increasing with the depth to be drilled and the weight of the equipment. The length ranges from 1,150 to 2,500 ft., depending upon the height of the derrick and the number of lines that it is necessary to string between the crown block and the hoisting block. Plow steel is a commonly used material in the manufacture of hoisting cables, though extra strong cast steel is used where exceptionally heavy loads must be handled. A cable composed of six strands of 19 wires each is generally used, the steel strands being twisted about a hemp core. Several different arrangements of the component wires make up the individual strands, and some variation in size and shape of the wires is to be noted in steel cables of different types. Cross sections of cables illustrative of some of the more common styles are displayed in Fig. 77. The American Petroleum Institute has adopted certain standards of strength and properties of materials that are observed by most manufacturers of oil-field equipment (see Table XVI).

The hoisting cable may be strung in either of several different ways. One end is always attached to the hoisting drum of the draw works, the other may be attached as a dead line on the hoisting block, fastened to one of the derrick sills, or, in the case of a combination rig, attached to the drum of the calf wheel. In the latter case the hoisting block may be lifted by reeling up either or both ends of the hoisting cable.

Crown Blocks.—The straight rotary crown block is usually equipped with four or five sheaves, mounted side by side on a single horizontal shaft supported in a position

parallel with the shaft of the hoisting drum of the draw works. Many operators prefer the double-deck type of crown block in which the sheaves are arranged at two different levels, the supporting shafts of those on the lower deck being at right angles to those supporting the upper deck sheaves. There are two sheaves on the lower deck and either three or four on the upper deck, the latter being usually larger than the former. In addition, a small "cat-line sheave" may be supported from one of the lower deck beams. For combination rigs of the California type two additional sheaves must be provided in the crown-block assembly, a crown sheave for the drilling cable and a sand-line sheave (see Fig. 78). The double-deck arrangement of the casing-line sheaves provides better alignment with the hoisting-block sheaves, and less flare or angularity in the lines, permitting the hoisting block to be raised higher



(*Courtesy of Emsco Derrick and Equipment Co.*)

FIG. 78.—Double-deck crown block.

in the derrick without destructive side drag and consequent wear on the sheaves and hoisting cable (compare with Fig. 43).

Crown-block sheaves range in diameter from 26 to 46 in. depending upon the purpose for which they are used. The larger diameter sheaves result in longer operating life for the hoisting cable. They are preferably of manganese or other wear-resisting steel, and the grooves should be accurately ground to fit the size of the hoisting cable used. The sheave pins or supporting shafts must be of sufficient diameter (often 4 to 8 in.) to support the loads imposed and are mounted on roller bearings to reduce friction. Lubrication is an important consideration, grease-gun lubrication being adopted by some manufacturers.

The supporting beams are usually heavy steel I-beams bolted together with web plates to form a substantial rigid frame. A five-sheave, double-deck crown block equipped with three 46-in. and two 26-in. sheaves, appropriate for a heavy rotary rig, weighs 6,300 lb.

The Drill Stem.—The drill stem connecting the drilling bit in the well with the hydraulic swivel in the derrick consists of sections of heavy steel pipe connected either

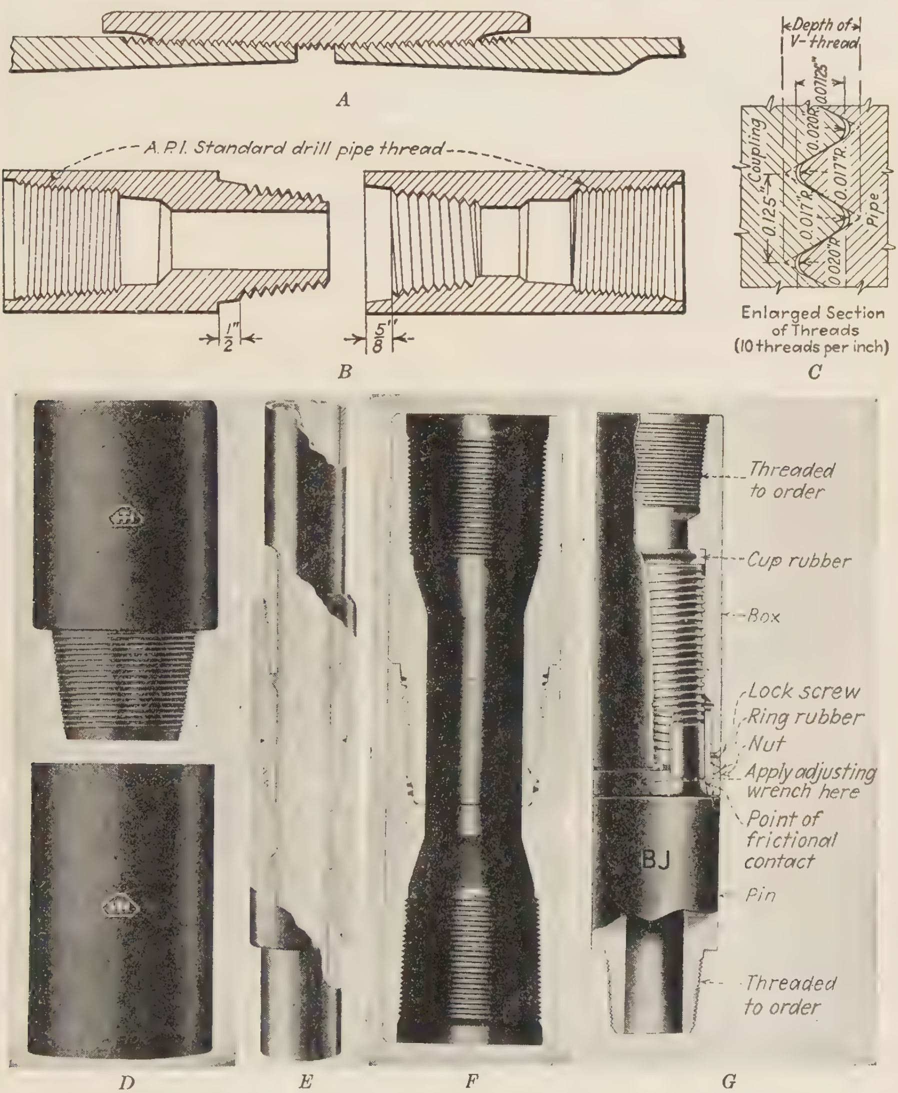


Fig. 79.—Rotary drill pipe and tool joints.

A, A.P.I. standard upset-end drill pipe; *B*, rotary tool joint, A.P.I. standard; *C*, detail, *D*, Hughes tool joint; *E*, Hydril flush-interior tool joint; *F*, Reed full-hole tool joint; *G*, B-J back-off safety tool joint.

by special pipe couplings or by "tool joints." The latter are used only at every third or fourth joint, depending upon the length of joints and the height of the derrick, and are designed to facilitate coupling and uncoupling of the stem as it is inserted into or withdrawn from the well.

Rotary drill pipe, the trade name applied to the special grade of pipe used for the drill stem, may be had in external diameters ranging from 2⅜ to 8⅝ in. Each size

may be had in two or more different weights or thicknesses (see Table XX). Selection of the size and weight of drill pipe depends upon the diameter and depth of the hole to be drilled. It is furnished by the tube manufacturers in nominal lengths of either 20 or 30 ft. with permissible variations of 2 ft. The material employed in the manufacture of drill pipe may be either Bessemer or open hearth, lap welded, or preferably a seamless tube of somewhat higher strength and carbon content. The latter type of material is exclusively used when the well to be drilled is a deep one. Upset-end pipe, with the extra metal on the inside, is now almost universally preferred because of its greater strength (see page 283). Figure 79*A* gives details of joint construction for rotary drill pipe as approved by the American Petroleum Institute. The couplings provided for drill pipe are of special design, with recessed threads and heavier-than-standard construction in order that they may withstand the severe strains imposed upon them. They are cut with eight 60-deg. V-shaped threads per inch—a deep thread in order to avoid stripping under severe strain.

TABLE XX.—A.P.I. STANDARD ROTARY DRILL-PIPE WEIGHTS AND SIZES
Size of A.P.I. drill pipe indicates outside diameter
(All weights in pounds)

Size O.D., in.	Size I.D., in.	Thickness of shell, in.	Weight per foot*: Plain end, lb.	Weight per foot*: Finished, lb.	Number of threads per inch	Mill test, lb. per sq. in.	Upset: Length, in.	Upset: Size I.D. at end, in.	Upset: Size I.D. full upset, in.	Couplings: Size, O.D., in.	Couplings: Length, in.	Couplings: Approximate weight, lb.
†2 3/8	2.000	.1875	4.380	4.800	10	2,500	3 1/4	1 7/16	1 7/16	3.125	5 1/2	5.575
2 3/8	1.815	.2800	6.264	6.650	8	2,500	3 1/4	1 3/8	1 1/8	3.125	5 1/2	5.575
2 7/8	2.469	.2030	5.793	6.450	8	2,500	3 1/2	1 7/8	1 7/8	3.750	6 1/2	9.260
2 7/8	2.323	.2760	7.661	8.350	8	2,500	3 1/2	1 7/8	1 5/8	3.750	6 1/2	9.260
2 7/8	2.151	.3620	9.715	10.400	8	2,500	3 1/2	1 9/16	1 3/16	3.750	6 1/2	9.260
3 1/2	3.063	.2187	7.665	8.500	8	2,250	3 1/2	2 7/16	2 7/16	4.250	6 1/2	9.710
3 1/2	2.900	.3000	10.252	11.200	8	2,500	3 1/2	2 1/2	2 1/8	4.250	6 1/2	9.710
3 1/2	2.764	.3680	12.309	13.300	8	2,500	3 1/2	2 3/8	1 7/8	4.250	6 1/2	9.710
4 1/2	4.000	.2500	11.347	12.750	8	2,000	5	3 3/8	3 1/4	5.500	8	19.930
4 1/2	3.958	.2710	12.240	13.750	8	2,200	5	3 9/32	3 5/32	5.500	8	19.930
4 1/2	3.826	.3370	14.983	16.600	8	2,500	5	3 1/32	2 13/16	5.500	8	19.930
5 9/16	4.975	.2940	16.544	19.000	8	1,900	5	4 9/32	4 1/8	6.750	8 1/2	30.772
5 9/16	4.859	.3520	19.590	22.200	8	2,250	5	4 5/32	3 13/16	6.750	8 1/2	30.772
5 9/16	4.733	.4150	22.817	25.250	8	2,500	5	3 7/8	3 1/2	6.750	8 1/2	30.772
6 5/8	6.065	.2800	18.974	22.200	8	1,600	5	5 3/8	5 3/16	7.750	9	36.580
6 5/8	5.965	.3300	22.186	25.200	8	1,800	5	5 11/32	5	7.750	9	36.580
6 5/8	5.761	.4320	28.573	31.900	8	2,400	5	5 1/16	4 5/8	7.750	9	36.580
†7 5/8	6.969	.3280	25.562	29.250	8	1,650	5 1/2	6 1/4	6	8.875	9 3/4	49.000
†8 5/8	7.825	.4000	35.137	40.000	8	1,800	6 1/2	7	6 5/8	10.000	10 1/2	70.800

* Weight per foot: Finished includes threads and couplings. "Weight per foot: Plain end" is without threads, couplings and upsets.

† On special order only.

In inserting and withdrawing the drill stem into and from the well, it is broken only at every third or fourth joint, and the resulting "stands" of drill pipe 80 or 90 ft. long are stood on end in one corner of the derrick. The couplings described in the preceding paragraph are ordinarily used only at joints that are not frequently unscrewed. The tool joints connecting these three or four joint sections of the stem are equipped with tapered screw joints somewhat similar to those used on cable tools, except that they have a cylindrical hole through their longitudinal axis for passage of the circulating fluid. They consist of two parts, one shaped with a "pin" and the other with a "box." On the opposite or outer end of each part, a recess tapped to receive the threaded end of the drill pipe is provided. The proportions of rotary tool joints, the dimensions and the character of threads have been standardized by the American Petroleum Institute as illustrated in Fig. 79*B*. Figures 79*D*, *E*, *F* and *G* are illustrative of different types of tool joints available from tool manufacturers. Figure 79*G* is intended for use immediately above the drill collar and permits of dis-

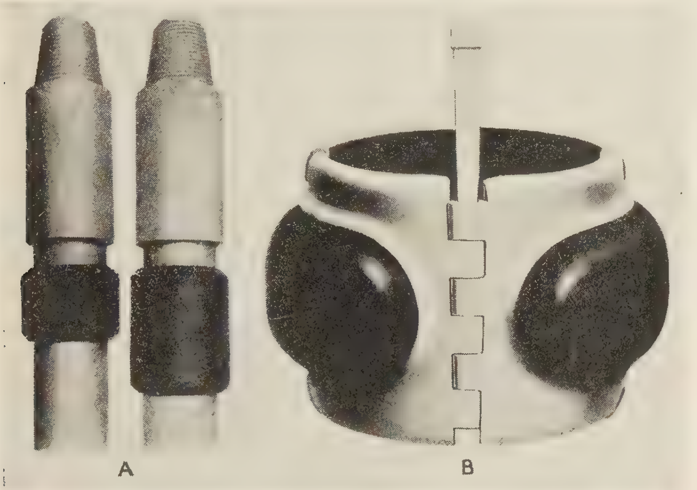


Fig. 80.—Drill-pipe protectors.

A, Bettis protectors (*courtesy of Patterson-Balagh Corp.*); *B*, "Grizzly" protector (*courtesy of E. M. Smith Co.*).

engaging the drill pipe by turning to the right at the surface in the event that the bit becomes frozen in the well.

The cylindrical drill stem is connected at its upper end with the square grief stem or "kelly" joint previously described. The latter is attached to the rotating element of the swivel. On the lower end of the column of cylindrical drill pipe, a drill collar is attached. This collar, which provides a means of attaching the rotary bit to the drill stem, must be of sufficient strength to withstand the great torsional and impact strains to which it is subjected. Every precaution must be taken against breakage of the stem and the connecting collars and tool joints, and the portion just above the bit is subjected to the greatest strain. The drill collar is equipped with a tool joint at the lower end and a pipe thread connection at the upper end. It is hollow to permit of passage of circulating fluid to the bit.

Drill-pipe Protectors.—There is considerable power loss in scraping of the rotary drill-pipe collars and tool joints against the wall of the well or the interior of any casing through which drilling operations may be conducted. Such friction also results in wear of the casing and drill stem, often to a highly detrimental degree, perhaps lead-

ing to twisting off of the drill pipe at a weakened joint and leaking or even collapse of the casing under stress developed by high hydrostatic heads. To overcome these disadvantages partially, many operators equip all drill pipe with rubber "protectors." These are made of heavy, cylindrical blocks of soft rubber molded to fit snugly on the outer surface of the drill pipe (see Fig. 80). They are slightly larger in external diameter than the tool joints, and one is placed near each tool joint and collar. All rubbing surfaces are rubber against metal, a combination which occasions much less wear and friction than metal against metal, particularly in the presence of a gritty fluid.

The idea of rubber protection against frictional drag and wear of the drill pipe has been further developed in the use of so-called "antifriction" tool joints and collars, in which a groove is machined to receive and support the rubber cylinder. The same

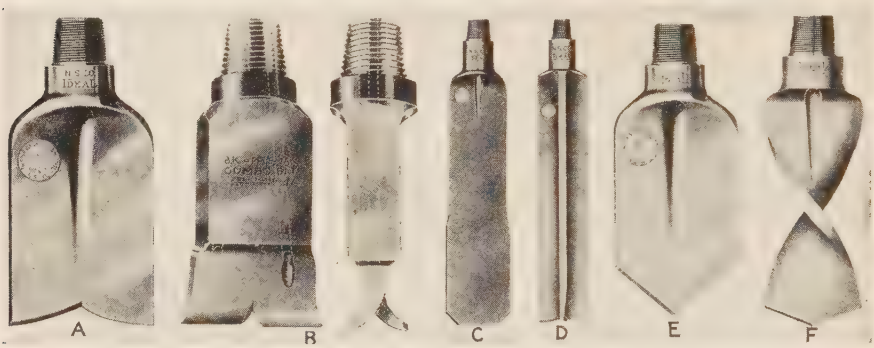


Fig. 81.—Types of fishtail and rotary reaming bits.

A, California type "Ideal" fishtail bit; *B*, Appleman gumbo bit; *C*, "Ideal" paddle reaming bit; *D*, "Ideal" four-wing reaming bit; *E*, diamond-pointed bit; *F*, side-tracking bit.

principle is made use of in the Bettis drill stabilizer, a large rubber cylinder placed on the lower end of the drill pipe a short distance above the bit. This device aids in keeping the hole straight and avoiding twist-offs of the drill stem, by minimizing eccentric motion, bending, whip and twist of the drill pipe.

Rotary Drilling Bits.—Many different styles of bits are used in rotary drilling, a choice depending chiefly upon the nature of the formation to be penetrated and the individual preference of the operator.

The first type of bit developed for use with the rotary equipment was the fishtail bit, still widely used in drilling soft and semiconsolidated formations. It is especially adapted to loosely cemented sands, shales and clays. When harder rocks are encountered, however, the bit is rapidly dulled and progress is slow. Various forms of fishtail bits are illustrated in Fig. 81. They are made of a special grade of tool steel, often of chrome steel, forged to a slender blade ranging from 15 to 30 in. in length, ½ to ¾ in. thick at the cutting edge and 1½ to 2½ in. thick at the top. The width of the blade at the cutting edge is only slightly smaller than that of the hole which it is desired to drill. The cutting edge is divided into two parts by fluted watercourses down the center of each side of the blade. The two cutting wings thus formed are dressed to a slight taper or bevel and turned back somewhat to form the cutting edges. The top of the flattened portion of the bit terminates in a round shank, externally screwed for connecting the bit to the drill collar on the end of the drill stem. Through each side of the shank a hole about ¾ in. in diameter is bored. Mud-laden fluid from the hollow drill stem emerges through these holes, sweeps down the side of the bit and is deflected upward on striking the bottom of the hole.

Special forms of fishtail bits are designed to discharge the mud fluid nearer the corners and cutting edges than in ordinary patterns, as illustrated in Fig. 81*B*. This feature is said to aid in getting quickly drilled, dense clays and shales into suspension in the well fluid, preventing the material from "balling up" on the bit, and also to minimize overheating of the cutting edges and corners when drilling in harder rocks. The "four-wing" or cruciform bit, with four blades, each shaped like half of a fishtail bit, set at right angles with each other, is used primarily for straightening and reaming holes that have become crooked or lost clearance (see Fig. 81*D*). Watercourses connecting with the hollow drill stem are provided between each pair of wings.

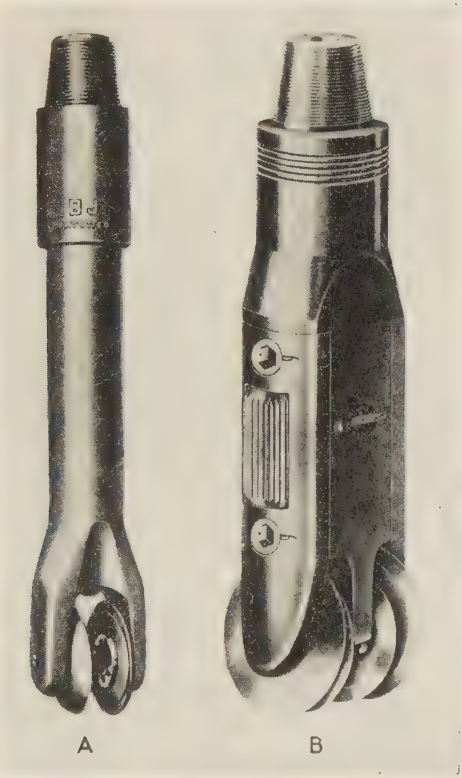


Fig. 82.—Types of disk bits.
A, Byron-Jackson two-disk bit; *B*, Guiberson four-disk reaming bit.

Another type of rotary bit useful in drilling soft and moderately hard formations is the disk bit, illustrated in two forms in Fig. 82. In this type of bit the cutting elements consist of two or more saucer-shaped disks, so mounted that they rotate on their slightly inclined supporting pins as the drill stem revolves. The edges of the disks are usually dressed to a smooth, sharp-cutting edge; in other models they are corrugated; and in some styles they are milled with cutting teeth. The disk bit applies a combined scraping and crushing action on the formation, effective in securing rapid advance in rocks of suitable hardness. The disks increase in diameter with that of the hole to be drilled but usually have about 13 times as much linear cutting edge as a fishtail bit used in drilling a hole of the same size. They therefore are capable of greater footage of drilled hole.

For hard-rock rotary drilling more intricate types of bits are used, which depend upon a crushing and chipping rather than a scraping action. The Hughes cone and Reed roller bits, designed to utilize this principle, are well known and widely used in oil-field drilling. The principal drilling elements in the Hughes bit consist of two cones on the surfaces of which there are milled a large number of cutting teeth (see Fig. 83*A*). The cones revolve on supporting pins in such a way that the element of the conical surface in contact with the bottom of the hole is almost horizontal or, preferably, inclined a few degrees below the horizontal from the axis of the tool. The main body of the tool consists of two semicylindrical segments, held together by a locking screw, and a massive drill collar screwed to the lower end of the drill stem. In addition to the cone cutters, four cylindrically shaped cutting rollers are mounted

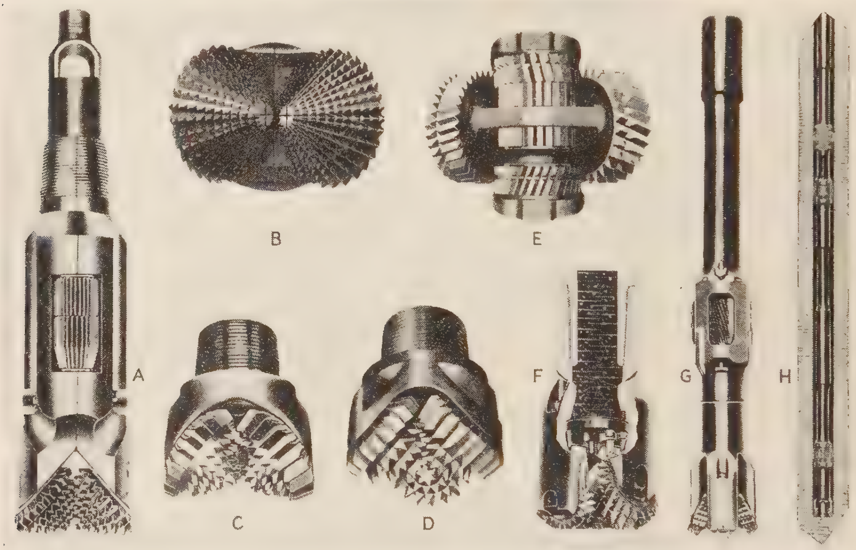


FIG. 83.—Types of hard-rock rotary bits.

A, Hughes simplex rock bit equipped with self-cleaning "Acme" cones; *B*, bottom view of Hughes simplex rock bit equipped with old-style hard-rock cone cutters; *C*, Hughes two-cone and *D*, three-cone roller-bearing rock bits; *E*, bottom view of Reed roller-bearing bit; *F*, sectionalized view of Reed roller-bearing bit, showing method of discharging circulating fluid; *G*, Reed roller-bearing bit with three-point reamer and *H*, with three reamers in tandem.

on two opposite sides of the cylindrical body. These rollers have teeth milled on their cylindrical surfaces, and they are so mounted that the rollers cut lightly into the vertical walls left by the cones. The rollers thus serve to ream the hole to a slightly larger diameter, giving all parts of the tool ample clearance and producing a smooth-walled and perfectly cylindrical hole. An elaborate oiling system is also provided. Watercourses conduct the mud-laden fluid from the hollow drill stem through the body of the tool to the revolving cones, against the surfaces of which the fluid is discharged under high pressure.

The Reed roller bit is equipped with eight disk-shaped cutters, having transverse teeth milled around their circumferences and mounted in a massive steel frame (see Fig. 83*G*). The disks are smaller in diameter toward the center of rotation in order to compensate for differences in rate of travel. The two cutters set at an inclination with the axis of the tool, as best shown in the bottom view (Fig. 83*E*), are provided to maintain clearance. Four or eight additional cylindrical cutters are mounted vertically on the circumference of the main body of the tool, serving to ream the hole further

and to give a smoother bore. A reservoir of lubricating oil in a lubricator attached between the drill collar and the bit is connected by oil courses with the moving parts. The circulating fluid is passed through the bit by two watercourses connecting with the drill stem and is discharged directly against the cutters.

Cone and roller bits are capable of making better progress and a much greater footage than is possible with fishtail or disk bits, particularly in hard rocks. This is in part due to the more efficient principle on which they operate and in part to the greater length of cutting edge which they present. For example, in a pair of 9⅞-in. cone cutters are 56 teeth, each 3 in. long, or a total of 168 in. of cutting edge as compared with perhaps 11 in. for the ordinary fishtail bit. The teeth and cutting edges of hard-rock bits, of course, gradually wear away under the abrasive action of the rock, and the moving parts must be occasionally replaced. This involves withdrawal of the tool from the well, disassembling and assembling the various parts with fresh cutters. The cutters may be redressed in a milling machine after annealing, for use in a smaller size of hole.

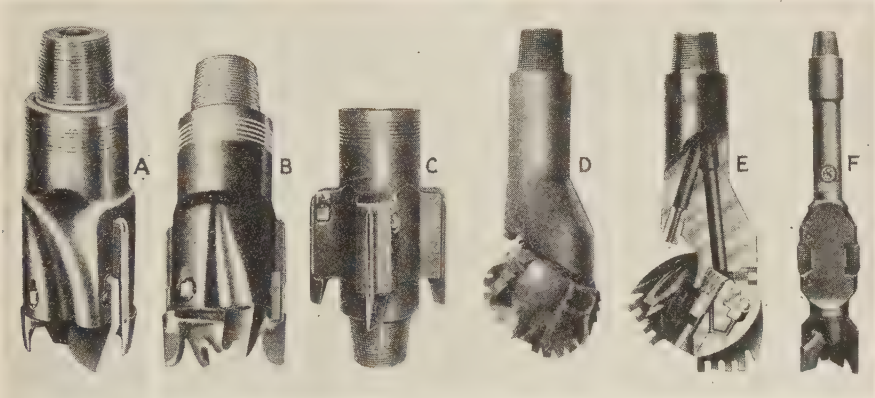


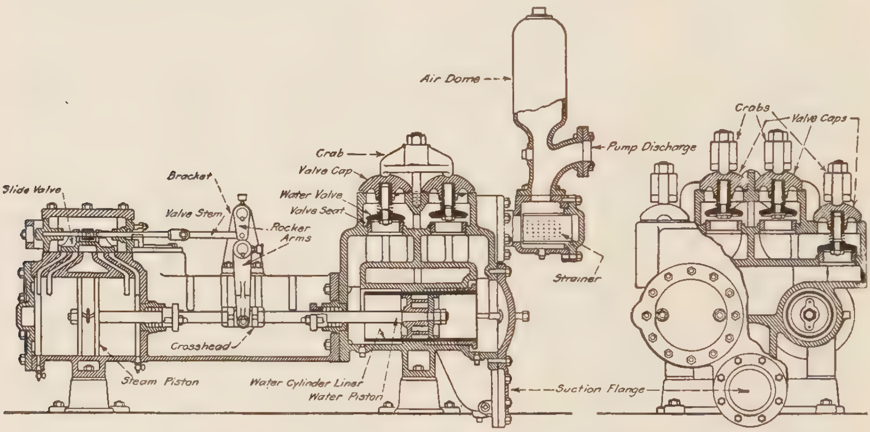
FIG. 84.—Types of demountable bits.

A, *B* and *C* are different styles of Kennedye-Plumb replaceable-blade bits and reamers; *D*, external view and *E*, sectional view of Zublin bit; *F*, Smith demountable bit and reamer.

Still another group of rotary bits, known as "demountable bits," are equipped with detachable drill heads, on which prongs or cutting teeth are cast or otherwise attached in such a way as to attack the formation from various angles as the tool revolves. Instead of trying to resharpen, the entire head of the tool is replaced by a new one when necessary. Figure 84 presents several different styles that are illustrative of this type. In a somewhat similar type, merely the cutting teeth or blades of the bit are replaced (see Fig. 84*A*–*B*). The Zublin bit is an interesting member of this group (see Fig. 84*D*–*E*). In this, the head, equipped with heavy, prong-shaped teeth projecting out at various angles, is mounted so that it turns eccentrically as the massive steel body of the tool revolves with the drill pipe. The cutting head is mounted on ball bearings to reduce friction. The peculiar method of mounting provides both up-and-down as well as rotating motion for the cutting teeth so that they function both as hammers and chisels. The manufacturers claim that this bit is efficient in any kind of formation, drills rapidly, mixes the cuttings with the well fluid thoroughly and is self-sharpening so that it maintains its cutting edges. It is claimed also that there are comparatively few twist-offs of the drill pipe with this type of bit and that it drills a straighter hole. The Reed collapsible bit, illustrated in Fig. 109*F*, is unique in that it is possible to replace the cutters without withdrawing the drill pipe from the

well. The replaceable elements are withdrawn and replaced by a steel cable operating through the drill pipe.

In order to resist breakage under the severe stresses to which they are subjected in service, rotary drilling bits are often made of low-carbon steel and then case-hardened to develop wear-resisting qualities. In heat treatment a compromise must be reached between hardness on the one hand and brittleness on the other. In seeking to improve the wearing qualities and the footage of hole drilled per bit, notable increase in drilling efficiency has been achieved by the use of hard-facing metals applied to the wearing corners, edges and faces. High-carbon steel, special alloy steels containing manganese, chromium, vanadium or tungsten, may be fused on with the aid of the oxyacetylene torch. Many different methods and systems of tempering and case-hardening are employed. Tungsten carbide, available on the market under a variety of different forms and trade names, is inserted in small pieces in cavities prepared in the bit, or embedded in fusion metal applied with the oxyacetylene torch. This material, next



(Redrawn with additions, from illustration in Lucey Corporation's Catalog No. 8.)

FIG. 85.—Sectional views of rotary slush pump.

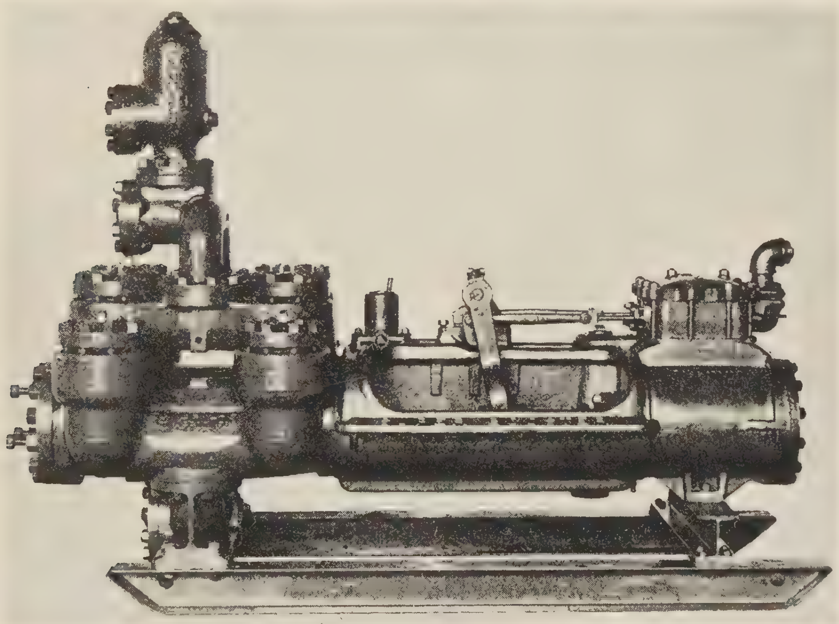
to the diamond, is the hardest substance known. It is also tough, so that it does not readily crush or crack under the high pressures to which rotary bits are frequently subjected in service. Though expensive, these hard-facing materials are profitably used because of the greater footage secured and because of reduction in loss of drilling time in changing bits.

Slush Pumps.—The pumps used in maintaining circulation of fluid through the well are usually of the steam-driven, duplex, double-acting type, with removable steel cylindrical liners and large valve areas on the water end to adapt them to use with thick muds which may at times carry gritty sands. Because of the nature of the fluid handled, it is important to have the valves, liners, packing glands and other wearing parts readily accessible for repairs. The steam valves are simple slide valves, positively controlled by rockers actuated by the pistons (see Fig. 85). The water-suction and discharge valves are of the winged-disk type, operating against heavy springs coiled about the valve stems. They are usually faced with rubber to insure tight seating.

Slush pumps are rated by the diameter of their cylinders and length of piston stroke. The steam cylinders range from 10 to 16 in. in diameter, the water cylinders from 5 to 8 in. and the stroke is either 12, 14, 16, 18, 20 or 24 in. Pumps of this type are frequently designed to operate under pressures as high as 1,500 lb. per square inch,

though operating pressures are often less than 200 lb. Steam ends are designed for pressures ranging from 125 to 350 lb. per square inch. Capacities depend upon the operating speed and the efficiency of the pump. The larger sizes range up to 630 gal. per minute in delivery capacity. Normal plunger speeds should not exceed 120 ft. per minute, the number of strokes ranging from 40 to 60 per minute, depending upon the length of stroke and capacity desired. Volumetric efficiencies (that is, actual delivery capacity divided by theoretical displacement capacity) may range as high as 85 per cent but average about 60 per cent when pumping the heavy muds used in rotary drilling. Weights range from 3,400 lb. to as much as 15,500 lb. for the larger sizes of slush pumps (see Fig. 86).

The water ends of these pumps are designed to receive liners of different sizes, thus making them adaptable to desired changes in delivery pressure without variation



(Courtesy of Emsco Derrick and Equipment Co.)

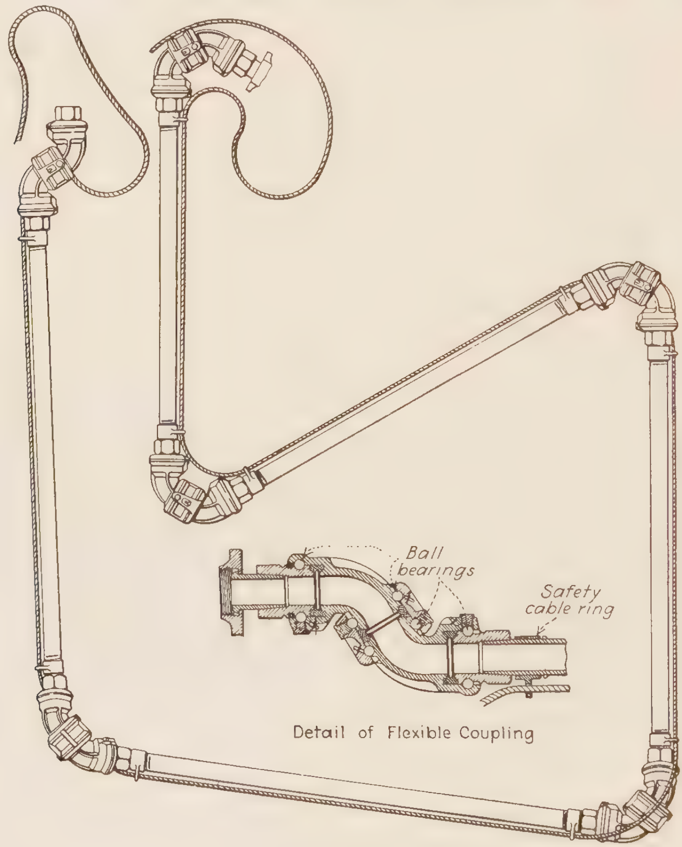
Fig. 86.—Heavy-duty slush pump.

in speed or power consumption. For very deep wells, where unusually high formational pressure must be contended with, small liners (3½ in.), capable of developing pressures as great as 3,000 lb. per square inch with normal steam pressure, are sometimes used. Two such high-pressure pumps are sometimes compounded and operated in tandem with one low-pressure pump to secure the necessary volumetric capacity at high pressure.

The pump suction lines are usually of 6- or 8-in. (in one model, 10-in.) pipe, equipped at the lower end with foot valves and strainers, well submerged in the mud pit. The suction lift should be as small as possible and should never exceed 15 ft. To absorb pulsations and induce a uniform flow in the discharge pipes, an air chamber is generally used on each pump. The delivery lines from the pumps, often 3 in. in diameter, are manifolded to connect with the armored swivel hose. Quick-acting valves are provided in the pump manifold to permit of promptly changing the flow from one pump to the other when desired.

Where electric power or internal-combustion-engine power must be used, the pumps are of the belt-driven or gear-driven type. Often the two pumps are driven by a single power unit where electric power is used, utilizing an intermediate countershaft or reduction-gear unit. With a suitable dual-drive arrangement, it is also feasible to operate both the draw works and pumps with a single source of power, which may be either an electric motor or a steam or internal-combustion engine.

Rotary Hose.—The flexible connection between the slush-pump manifold and the gooseneck of the rotary swivel usually consists of an armored hose of rubber and



(Courtesy of Oil Equipment Sales Corp.)

Fig. 87.—Hamer all-steel rotary hose.

canvas 2 or 2½ in. in diameter. The high pressure to which it is subjected requires a hose of especially heavy construction. One commonly used brand is composed of eight thicknesses of fabric, embedded in a rubber matrix throughout the greater part of its length, with 10-ply material at the ends. In addition, it is closely wound with heavy wire. Two 30-ft. lengths of hose, connected by a coupling and two pair of clamps, are necessary to provide for the vertical movement of the hydraulic swivel.

High pump pressure incidental to deep drilling operations has necessitated use of the heaviest grades of hose available. Security of the hose connections at the swivel gooseneck and the standpipe connecting with the pump manifold requires unusually substantial hose clamps. A notable advance in the development of flexible

connections between the pump manifold and the swivel, secure against high pressure, has been effected in the all-steel rotary "hose." In this, the necessary flexibility is attained by the use of relatively short lengths of steel tubing, connected by ball-and-socket joints or ball-bearing joints of special design. The greater the pressure, the less tendency there is for this type of joint to leak. One type of all-steel drill hose, constructed as illustrated in Fig. 87, makes use of five joints of 3½-in., 12-lb. drill pipe, connected by ball-bearing joints. The several joints are also tied together with a light steel cable.

MANIPULATION OF THE ROTARY EQUIPMENT IN DRILLING

Starting the Well.—With the rotary equipment completely rigged, with mud in the slush pit, steam in the boiler and all in readiness for drilling, a drilling bit of the size selected as the initial diameter of the well is securely screwed to a drill collar and the latter on one end of the grief stem. To the top of this the rotary swivel is connected, which, in turn, is suspended from the hoisting block (see Fig. 76). The bit, collar, and stem, connected as described, are then lowered through the rotary table into the conductor pipe until the bit is within a foot or so of the point at which drilling is to be started. Lowering of the drill stem is accomplished by partially releasing the brake on the hoisting drum, clamping the brake when the tools have reached the desired position. The driving bushings are then inserted in the table, one of the pumps is started and the table clutch thrown in. As the stem revolves, the hoisting-drum brake is again released and the tools are lowered until the bit begins to cut into the material in the bottom. The sludge soon reaches the surface and overflows into the mud ditch, which returns it to the slush pit after the coarse material has settled out. Frequently the drill collar will be fastened permanently to a joint of drill pipe by babbitting a recess left above the threads. In this case, it will not be possible to use the grief stem until the well attains a depth of 20 ft. or more, the stem being rotated meanwhile by grip rings mounted on top of the table.

Adding a New Length of Drill Stem.—At intervals of 20 or 30 ft., as the hole is deepened, it will be necessary to add a joint of drill pipe to the stem. The slush pumps are stopped, the table clutch is thrown out of gear, the driving bushings are removed from the table and the stem is raised by applying power to the hoisting drum. As the joint at the lower end of the grief stem emerges above the table top, the drill-pipe slips are placed in the table opening about the pipe and the stem is lowered slightly until the slips take hold. The table is then locked so that it cannot revolve, and the pipe tongs are applied above the joint, aided by a jerk line from one of the cat-heads on the draw works. When the joint has been loosened with the aid of the power, it can be unscrewed by hand, the three floor men of the crew grouping themselves about the stem and passing the tongs rapidly from one to another until the threads are disengaged. The grief stem and swivel are then hoisted until clear of the lower portion of the joint, then lowered and stood on end in one corner of the derrick, or lowered into a "rat hole" made by rotating two joints of 8-in. pipe under the derrick floor. The hook is then disengaged from the swivel bail and the casing elevators placed on the hook in its stead. Meanwhile, a joint of drill pipe has been

brought into the derrick from the pipe rack with the aid of a casing carriage. The elevators are lowered, clamped under the collar on one end of the joint and the joint is raised until it hangs vertically in the derrick. After removing the protecting collar on the new joint of pipe, and "doping" the threads thoroughly, it is carefully lowered into the open collar of the portion of the stem supported by the slips in the table. Tongs are then applied to the new joint, first by hand methods and finally with the aid of the power, connecting a jerk line from the handle of the tongs to one of the catheads on the draw works. When the new joint has been securely attached in this manner, the weight of the stem is transferred from the table to the crown block by hoisting the stem for a short distance and removing the slips. The stem is then lowered until the collar of the new joint is about 2 ft. above the table. The slips are again placed in position, and the stem lowered until the slips take hold. The elevators are then disengaged and removed from the hoisting-block hook, before engaging the bail of the swivel. If the hook is large enough, the elevators may be left on the hook. The swivel and grief stem are then raised until clear of the derrick floor, swung to the center of the derrick and, after doping the joint, gently lowered until the lower end enters the collar on the upper end of the new section of drill pipe. Application of the tongs and slightly raising the stem until the slips can be removed from the table completes the work. The pumps are then started, the stem is lowered until the bit is a few inches off bottom, the drilling bushings are placed back in the table and drilling is resumed. This procedure is followed with each joint of pipe added to the stem, except that at every third or fourth joint (depending upon the height of the derrick and the preference of the driller) a tool joint is used instead of the usual pipe coupling.

Replacing a Dulled Bit.—When slow progress indicates that the bit has become dull, the entire stem must be withdrawn from the well and unscrewed into "thrible" or "fourble" stands of three or four joints respectively, that is, the stem is broken at each tool joint. The pumps are shut down, the rotary table disengaged from the power and the tools hoisted until the joint at the lower end of the grief stem emerges above the table. This joint is unscrewed by application of the tongs as described above, the swivel and grief stem placed in one corner of the derrick or in the "rat hole" and the elevators substituted for the swivel on the hoisting-block hook. The elevators are next lowered until they can be clamped under the tool joint on the upper end of the stem projecting above the table. The stem is then hoisted in the derrick until three or four joints of pipe have passed the table and the next tool joint emerges. The slips are dropped into place around the stem, the latter is lowered slightly until the slips take hold, the table is locked and the tool joint is broken. The disconnected section of drill stem, now suspended on the elevators, is swung over into one corner of the derrick and lowered until the lower end rests on the derrick floor. Meanwhile the derrick man has been sent up into the derrick and has taken his place on the thrible board or fourble board (depending upon whether three- or four-joint stands are in use), which places him at an elevation level with the top of the stand. The derrick man guides the upper end of the stand into its position of rest against the "finger" board and disengages the elevators. The elevators are then lowered, a hold taken under the tool joint on the upper end of the next "stand" and the process is repeated until the entire stem is disconnected and the bit emerges from the well.

With a skilled rotary crew, this work of drawing out and uncoupling the stem proceeds with clocklike precision. Each of the five men constituting the crew has a definite part to perform. The driller controls the engine and the draw-works clutches and brake. Three of his helpers work on the derrick floor about the rotary

table, manipulating the pipe tongs, elevators and slips, and swinging the lower end of the stands to their position at one side of the derrick. The part of the derrick man has already been described. As much as 1,000 ft. per hour of 6-in. drill stem, connected in three-joint stands, can readily be withdrawn and uncoupled in the manner described, or at the rate of one stand every 3 min. A skilled crew can uncouple drill stem even more rapidly than this for short periods of time, but the work is tiring and fraught with some danger to the crew and to the equipment unless carefully performed. Hence undue haste is not encouraged.

When the bit emerges from the well, the table bushings must also be removed, and while out of their usual position, the opening through the table should be covered to prevent anything from falling through. The possibility of the bit dropping through the table opening as it is unscrewed from the drill collar must be guarded against particularly. After unscrewing the bit from the collar a sharpened and properly gaged bit is substituted, and the new bit must then be lowered to bottom by coupling the sections of drill stem together again, a process precisely the reverse of that outlined above for withdrawing it. Each joint is doped before the stands are coupled together.

Drilling with the Rotary Tools.—As the rotary bit revolves on the "formation" in the bottom of the well, its effect will vary with the amount of pressure applied. If there is insufficient pressure on the bit, it will slide or drag over the rock face, loosening grains or fragments of material only occasionally, so that progress will be slow; the bit will be rapidly dulled and will lose its gage. If, on the other hand, too much pressure is applied, the bit will embed itself in the rock to such a depth that it cannot cut itself free and will chatter up and down as it revolves. Excess of pressure on the bit throws so severe a strain on the equipment at such times that breakage of the bit or a twist-off of the drill stem is very likely to occur. Furthermore, the hole is apt to be crooked. With the proper pressure on the bit, the tool is forced to embed itself in the formation just enough to permit of its chipping away the rock in small fragments as the stem revolves. Under such conditions there will be a minimum of grinding action and the maximum footage will be obtained.

It is apparent that the most effective pressure will vary with the character of the rock and the size of the bit, the harder rocks and the larger bits requiring the heavier pressures. Table XXI indicates recommended pressures for Hughes cone bits in three common types of hard rocks and for a variety of sizes of drills. Being based on a straight-line relationship, the pressure can be reduced to a certain amount per inch of diameter, which varies from 1,000 to 1,600 lb. in the three type rocks listed. These figures are the result of experimental work on a large scale conducted by the Hughes Tool Company.

A committee representative of a large group of mid-continent operators assembled the data of Table XXII, which are said to be representative of average table speeds and bit pressures in the Texas, Louisiana and Arkansas fields. The bit pressures are expressed in total pounds pressure per inch of diameter of the hole.

TABLE XXI.—RECOMMENDED BIT PRESSURES FOR USE WITH HUGHES CONE BITS*

Size of bit, in.	Revolutions per minute	Pressure to be placed on bit: Moderately hard sandstone, lb.	Hard lime, lb.	Granite or basalt, lb.	Gallons of mud per minute	Size of drill stem, in.
4¼	50–70	4,200	5,300	6,700	10	3
5¾	50–70	5,700	7,400	9,100	40	3
6¼	50–70	6,200	8,000	9,900	25	4
7¾	50–70	7,700	10,000	12,300	60	4
8½	45–65	8,500	11,000	13,600	85	4
9¾	45–65	9,700	12,600	15,500	130	4
10½	45–65	10,500	13,600	16,800	110	6
12	30–50	12,000	15,600	19,200	160	6
13¾	30–50	13,700	17,800	22,000	240	6
16	30–50	16,000	20,400	25,600	340	6
18	30–50	18,000	23,400	28,800	440	6

* From pamphlet published by Hughes Tool Co.

TABLE XXII.—BIT PRESSURES AND TABLE SPEEDS USED IN ROTARY DRILLING WITH VARIOUS TYPES OF BITS AND IN DIFFERENT TYPES OF ROCKS IN THE MID-CONTINENT FIELDS*

Type of bit; rocks	Bit pressure, lb. per in.	Table speed, r.p.m.
Fishtail Bit		
Gumbo	600–1,000	50–80
Shale	700–1,000	60–80
Sand	500– 700	50–70
Rock Bit		
Chalk	600–1,000	65–80
Lime rock	600–1,200	60–80
Sand rock	800–2,000	60–70
Hard-formation Core Bit		
Shale	800–1,000	20–40
Chalk	1,000–1,500	20–40
Lime rock	1,000–1,500	20–40
Sand rock	800–1,200	20–30
Soft-formation Core Bit		
Gumbo	400– 600	20–40
Shale	400– 600	35–45
Sand	300– 500	25–40

* After J. F. Dodge in A.P.I. *Bull.* 204, p. 46, 1930.

A study of bit pressure in its relation to cutting speed in one of the Oklahoma fields indicates that considerably higher bit pressures than those suggested in Tables XXI and XXII may be advantageously used. Table XXIII presents the results. The data show that there is an almost constant increase in cutting speed, proportional to the increase in weight employed. At 41,000 lb., there is a tendency for 6-in. drill pipe to bend and kink, with likelihood of twist-offs. While the drill pipe may perhaps be safely operated with bit pressures as high as 41,000 lb., many operators prefer to use lower bit pressures in order to avoid excessive deflections of the hole from the vertical. One prominent California operator considers it good practice to use bit pressures of not more than 8,000 lb. when drilling with fishtail bits in soft shales and unconsolidated formations, and from this up to 12,000 lb. when drilling in harder formations.

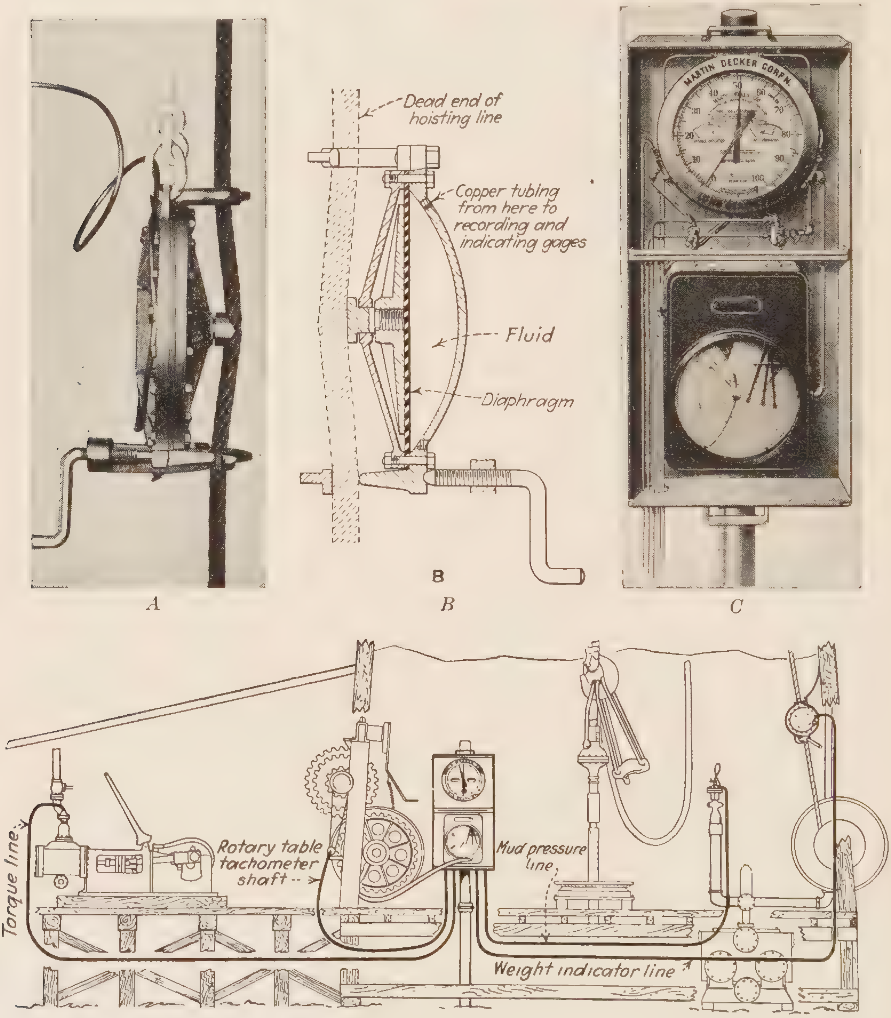
Table XXIII.—Influence of Bit Pressure on Cutting Speed in Different Types of Rocks*

Weight on bit, lb.	Formation				
	Lime, ft. per hr.	Sand, ft. per hr.	Sandy lime, ft. per hr.	Shale, ft. per hr.	Sticky shale, ft. per hr.
23,000	1.9	....	....	2.94	2.47
26,000	2.5	4.0	....	2.95	3.23
29,000	3.4	3.04	....	2.97	2.80
32,000	3.78	5.24	....	3.72	2.38
35,000	3.9	4.76	3.03	4.19	3.7
38,000	3.0	4.14	3.85	4.13	4.44
41,000	4.1	4.05	4.99	3.94	3.5

* After R. S. Cartwright, "Petroleum Development and Technology, 1928–1929," p. 20, Am. Inst. Mining Met. Eng.

Computation of the weight of the drill stem at varying depths and comparison with the figures suggested in Tables XXI and XXII indicate that at shallow depths the total weight imposed on the drilling tool will be somewhat below the pressure specified, while at greater depths the total weight of the stem will be greatly in excess of that necessary. The heaviest grade of 6-in. drill pipe averages approximately 30 lb. per foot, including collars and tool joints. A 6-in. swivel will weigh approximately 900 lb.; a 6-in. by 28-ft. square grief stem, about 2,900 lb.; a drill collar, say 150 lb.; and a 12-in. fishtail bit, about 200 lb. Adding these figures together, for a column of drill pipe with bit and equipment of the sizes indicated, we obtain a total weight at 250 ft. of about 11,400 lb.; at 500 ft. of about 19,000 lb.; at 1,000 ft. of about 34,000 lb.; and at 3,000 ft. upward of 94,000 lb. These weights will be reduced about 15 per cent by the buoyant force of the fluid in the well and to some extent also by contact with the walls of the well. Even if we ignore these corrections,

it is apparent that there will be insufficient weight on the bit for best results when drilling in sandstone requiring a pressure of 1,000 lb. per inch of diameter (12,000 lb. for a 12-in. bit), even if the full weight of the



D

(*Courtesy of Martin-Decker Corp.*)

FIG. 88.—Martin-Decker weight indicator and quintuplex drilling control instrument.

A, side view and *B*, sectional view of Martin-Decker weight indicator; *C*, Martin-Decker instrument indicating weight on bit, torque on drill pipe, speed of rotation of rotary table and pump pressure; also gage showing continuous record of drill-pipe weight and torque and mud pump pressure; *D*, sketch showing connections for drilling control instruments.

stem is imposed, until a depth of something more than 250 ft. is reached. But at greater depths the weight increases rapidly until at 3,000 ft. only about one-eighth of the weight of the stem should be permitted to bear

on the bit. This means that the driller must so control the hoisting-drum brake that seven-eighths of the load is borne by the crown block. It is apparent that a sensitive hand on the brake lever is necessary to bring about a proper distribution of load; good judgment in engine speed is equally important.

With the usual rotary equipment the driller can only guess at the amount of pressure on the bit and must base his control of the apparatus largely upon what his experience has taught him is proper for the particular hardness and kind of rock in which the bit is working, and for the depth and size of the hole being drilled. He is able to form some opinion of the working pressure on the bit by the action of the drill stem and by the resistance to his downward pressure on the hoisting-drum brake lever. He must adjust the speed of the engine to accord with the pressure applied and with the size of the bit used—a large bit under heavy pressure requires slow speeds, while with a small bit or a low pressure a rapid rotation of the drill stem produces best results.

Weight Indicators.—To aid the driller in maintaining proper bit pressure, several different types of weight indicators have been developed, one or another of which is generally provided as a part of the equipment of a modern rotary rig. One of these, that has probably been used more than any other, is illustrated in Fig. 88. This device indicates on a pressure gage the tension in the hoisting cable, which is necessarily a function of the bit pressure. The "dead line" of the hoisting cable, attached either to the shaft of the calf wheel (in the combination rig), or to the derrick sills, supports the weight indicator. The instrument is clamped on the cable in such a way as to form a kink in the line, which tends to pull straight under load. In so doing, it exerts a mechanical pressure proportional to the load against a diaphragm. This pressure on the diaphragm develops hydrostatic pressure on fluid, which communicates through tubing with the pressure gage placed in a position convenient for the driller's observation as he stands at his control post at the side of the draw works. Each unit of pressure registered on the pressure gage represents a definite load value on the hoisting cable. The gage reading may, by simple calculations involving the number of lines strung to the hoisting block and the length of drill pipe in use, become a positive measure of the weight bearing on the drilling bit. By observing the weight registered when the bit is just off bottom and, again, when the bit is in operation on bottom, the weight bearing on the bit can be quickly computed. Friction of the drill pipe on the walls of the well introduces a certain inaccuracy into estimates of bit pressure based on observations with this instrument, but it is thought that in most cases the error so introduced will not be excessive.

Another method of mechanically recording bit pressure by measuring tension in the dead line of the hoisting cable makes use of what is essen-

tially a heavy spring balance equipped with a mechanically actuated dial pointer. Still another device measures the compressive force developed by elastic deflection of the derrick, which is supposed to vary in a certain ratio with the load suspended from the crown block.

Mechanical Action of the Rotary Bit.—In order that a rotary bit may make progress in advancing the depth of a hole, it must first achieve a certain degree of penetration. This is accomplished as a result of the pressure applied on the drilling tool by the heavy column of drill pipe, the amount of penetration increasing with the weight allowed to rest on the bit. An important factor influencing penetration is also found in the shape and size of the cutting edges presented by the bit to the formation. A tool presenting a thin edge, or a number of slender prongs of relatively small cross section, will be forced farther into the formation with a given bit pressure than one presenting a broad flat surface of large superficial area. The hardness and density of the material in the bottom of the hole determine the resistance to penetration and displacement offered.

Having penetrated the formation, the bit disintegrates the rocky material immediately in the path of the cutting edge or teeth by its axial rotation. This involves a certain degree of shearing or cutting action, which is resisted by the cohesion and elasticity of the material. Generally, the greater the penetration, the coarser will be the fragments broken from the formation. The penetration of the bit and speed of rotation must not be greater than the power available will justify, or such as will create a stress in excess of the safe torsional strength of the rotary drill stem.

The bit finds relief from excessive penetration by vertical movement made possible by the elastic deflection of the drill pipe. The stem chatters up and down, and as a result the bit develops a certain degree of impact action, effective in crushing the formation. Such action, however, has a destructive effect, tending to cause breakage of the bit and twisting off of the drill stem.

The work done in pulverizing rock is proportional to the reduction in diameter attained. The area of fractured surface created by action of the bit is, in some degree, a measure of the energy expended. It is doubtless more efficient, in so far as disintegration of the formation is concerned, so to control the operation of the bit as to produce coarse rather than fine particles. The advantage so gained, however, is partially or perhaps completely offset by the greater expenditure of energy required to lift the coarser particles to the surface through the medium of the circulating fluid. It seems probable that for a given type of material and for a given density and viscosity of circulating fluid, there is a certain size of particle which represents the most efficient size from

the standpoint of total power expended. Either coarser or finer breaking of the material will occasion increase in power consumption.

In addition to its function of pulverizing the formation penetrated by the well, the drill must also assist in bringing the cuttings into suspension in the well fluid. The bit must not break material faster than the circulating fluid can carry it away. Mixing of the cuttings with mud fluid must be so thorough that the tendency of the coarse particles to "float" or remain in a stationary position in the ascending well fluid is reduced to a minimum. Coarse particles so retained in suspension in the well fluid are a potential cause of "frozen" pipe, by settling about the bit in the event that circulation is interrupted.

The clearance spaces about the bit through which the circulating fluid and entrained cuttings rise toward the surface should be of such cross-sectional area as will assure a proper ascending velocity. This, of course, depends also upon the volume of fluid circulated per unit of time. Among other factors, the lifting capacity of the circulating fluid for rock fragments depends upon its flow velocity. The ascending velocity of the fluid about the bit should be no greater than at higher levels. There is thus no tendency for the fluid to lift broken material off bottom until it is fine enough to be swept at uniform speed to the surface. Material too coarse for the fluid to lift will be left on bottom until it is crushed to smaller size by the bit.

Mechanical Action of the Drill Stem.—The length of the drill stem being many hundreds or even thousands of times its diameter, the drill stem is capable of considerable elastic deformation between the rotary table at the surface and the bit at the bottom of the hole. Doubtless, it acquires many degrees of torsional twist in normal operation, the amount of twisting and torsional strain varying with the bit pressure applied, the length of stem, the penetration of the bit and resistance offered by the formation to breaking out. In operation the lower portion of the stem is normally under compression, since it must provide downward pressure on the bit. As has been shown in a previous section, the downward pressure applied may range to upward of 40,000 lb., which represents the weight of about 1,400 ft. of 6-in. drill pipe. A 1,400-ft. column of 6-in. pipe subjected to so great a load naturally incurs considerable deflection, which is necessarily greater near the bottom where the greater compressive stress is attained. The pipe is deflected to develop pressure contact with the walls of the well, in extreme cases probably forming a corkscrew-like position in the hole for hundreds of feet above the bit. This flexible "corkscrew" is revolved with rapid variation in stress as the bit alternately digs into the formation and breaks free. There is doubtless considerable "whipping" of the pipe from side to side in the hole. Its eccentric motion is complicated by the vertical movement of the helical

segments of the stem as the bit pressure and torsional and bending stresses vary within wide limits. When the drilling bit must jump to free itself from excessive penetration, severe impact stresses are developed in the stem.

In deep drilling the upper part of the drill stem is under tension, since at least a part of the total weight must be suspended from the swivel. It therefore functions as a column under torsion and tension and therefore behaves in quite a different manner from the lower portion of the stem which, as explained above, functions as a distorted column under torsion and compression. It is clear that there must be some neutral position in the column of drill pipe at which there will be only the torsional stress developed by rotation.

The stresses developed are occasionally sufficient to cause failure or twist-off of the drill pipe. Such failures are usually in the lower part of the stem, near the bit, where the maximum bending and compression stresses occur. It is thought that metal fatigue and impact stresses occasioned by vibration and jumping of the bit in breaking out of the formation as a relief from excessive penetration probably play an important rôle in causing twist-offs of the stem. These stresses are doubtless accentuated by excessive rotational speeds. Studies of the stresses developed in drill pipe in their relation to the torque applied to the rotary table have shown that comparatively few twist-offs are due to torsional strain, there being normally a safety factor of from 1.5 to 9.

In drilling 246,000 ft. of hole ranging in diameter from 7⅝ to 20 in., in various California fields, using drill pipe of diameters ranging from 3½ to 8⅝ in., a total of 568 twist-offs were recorded or an average of 2.3 per 1,000 ft. of hole drilled. Of these, 348 occurred in the drill pipe proper, 208 in the upset portion of the pipe near the collars and tool joints, while only 12 failures occurred through the threads.

Many operators discard drill pipe after a certain amount of use in the belief that "crystallization" caused by metal fatigue is likely to promote twist-offs, which often occasion prolonged and costly fishing jobs. Opinions differ concerning the amount of hole that a drill stem should make before being discarded. Individual strings of drill pipe may at times yield a footage as great as 50,000 without excessive breakage. A general rule adopted by one successful California operator is that 1 ft. of pipe should drill 5 ft. of hole, or, in other words, that one string of pipe will drill five holes to a given depth.

Indifferent success has been attained in efforts to normalize fatigued drill pipe by special heat treatment. The results are somewhat uncertain, and individual joints respond to the treatment in varying degree. Many operators believe that in view of the lack of dependability of reconditioned pipe the cost of such work is better applied toward the purchase of new pipe.

The torque applied to the drill pipe by the rotary table is a convenient measure of the energy expended in drilling and of the twisting effort responsible for the torsional strain developed in the drill stem. In a steam-powered rotary rig a recording pressure gage on the engine side of the throttle valve provides a convenient torque indicator. A wattmeter recording the power input to the motor may be used for the same purpose when the rotary rig is electrically driven. Losses in the power and transmission mechanism are such that the power input on the prime mover is approximately proportional to the twisting effort transmitted to the drill pipe.

The action of the bit and the stress in the drill pipe are directly influenced by the speed of rotation of the table. The rapidity of rotation must be proportioned to the bit pressure and penetration. All of these variables must be adjusted to accord with the character of formation in which the bit is operating. Rotational table speeds may vary from 20 to 150 r.p.m. In some fields, operators believe that a speed of 60 r.p.m. should not be exceeded. A successful operator in one of the deeper California fields, where drilling is conducted for the most part through comparatively soft formations, prescribes a table speed of 80 to 90 r.p.m. for drilling and reaming and 40 r.p.m. for coring.

More accurate control of drilling operations is secured by the use of a table tachometer, which indicates or records the rotating speed of the table. This device consists of a small direct-current generator equipped with permanent magnets. The voltage of this type of generator is always directly proportional to its speed. The generator may be belt driven from the table pinion shaft or from the shaft on the draw works which transmits the drive to the table. A voltmeter, suitably calibrated, indicates the rotational speed to the driller at all times; or, if desired, a recording instrument may be used which will provide a continuous record of rotational speeds of the table. Such a record, studied in relation to similar records of bit pressure and table torque, provides a useful means of correlating the controllable mechanical variables with performance. The most advantageous conditions for drilling through different types of formations and at different depths may thus be prescribed. Causes of crooked holes, twist-offs of the drill pipe and other difficulties of drilling may be determined by this means.

The Martin-Decker quintuplex drilling control instrument, illustrated in Fig. 88*C* and used in conjunction with the rotary equipment as illustrated in Fig. 88*D*, continuously indicates the bit pressure, the load on the derrick, the drill-pipe torque, table speed and slush-pump pressure. A single recording gage equipped with three pens provides a continuous record of drill-pipe weight, torque and slush-pump pressure on one chart.

The causes of crooked holes in rotary drilling have been the subject of a great deal of discussion among engineers, and careful studies have

been made to determine the reasons for holes deviating from the vertical and to prescribe appropriate remedies. Development of dependable well-surveying instruments has made it possible to determine with certainty the points at which deflections occur and to correlate such information with the drilling records. Most authorities agree that bit pressure is probably the most important cause of crooked holes—excessive bit pressure must be avoided. It seems probable, also, that holes are sometimes caused to deviate from the vertical by the use of excessive pressure on the circulating fluid. Rapid circulation causes fluid to be jetted through the holes in the rotary bit with a force which is probably sufficient to erode away the walls of the well, possibly forming cavities in soft material, which may cause the drill pipe to bend and the bit to change its course. The hole must be started vertically; improper alignment of the drill pipe during the spudding process may permit the bit to work off at an angle from the vertical at the start of operations. The design of the bit used is also an important consideration in avoiding crooked holes. The bit should be of a form and size that will prevent undue eccentricity during rotation. The bit should be sharp and dressed out to proper gage. The drill collar, by which the bit is attached to the lower end of the column of drill pipe, should be large enough in diameter and of sufficient length to hold the pipe centrally in the hole and prevent buckling which, under excessive bit pressure, might cause the bit to work off to one side. Some operators use a few joints of oversize drill pipe just above the drill collar to resist bending stresses better. "Rat holing," or drilling ahead with a small bit and then reaming out to full size—often practiced in core drilling—is considered to be a likely cause of crooked holes, inasmuch as the small drill probably starts off center. This difficulty may be overcome by the use of guides or pilot bits on the drill pipe, or by centering the small drill in the well by rotating a diamond-pointed bit on bottom before inserting the smaller tools.

Many drillers believe that any hard, steeply inclined bed encountered in drilling a well tends to deflect the bit so that the axis of the well is inclined in the direction of the dip of the formation. Well surveys have shown this to be true in the case of wells-drilled with cable tools, but, curiously, with rotary tools, the reverse is often true, especially when the formations are not too steeply inclined. Instead of drifting down the dip of a hard stratum, a rotary-drilled hole in many cases, turns the other way and tends to assume a course at right angles to the dip of the formation. In very steeply inclined formations, on the other hand, surveys have shown that rotary-drilled wells, like cable-drilled holes, tend to drift down the dip. The tendency of some rotary-drilled holes to deflect into the hard inclined stratum is plausibly explained on the theory that encountering hard formation in the bottom on one side of the hole causes deflection of the stem immediately above the bit toward the opposite side.

Generally speaking, straight holes can only be achieved at the expense of slower drilling progress. Up-to-date operators are finding it worth while to use light bit pressures and low circulating pressures and to take all possible precautions to keep the hole vertical and straight, even though it means slower progress. Frequent use, during the progress of drilling, of surveying instruments or devices to indicate when wells begin to depart from the vertical makes it possible for the operator to remedy the difficulty before the deflection has become excessive. Plugging back and redrilling under moderate bit pressure will generally straighten the hole. The penalties for crooked holes and the instruments and methods employed in making well surveys are discussed in Chap. XII.

While operating conditions and other considerations usually make it desirable that the well be drilled as nearly vertical as possible, circumstances sometimes arise wherein it is desirable or necessary to deflect the well in some direction from the vertical. Some success has been had during recent years in purposely deflecting wells to reach objectives not vertically beneath the starting point at the surface. This may be done with the aid of bent drill collars, "side-hill" and eccentric bits, knuckle joints and fixed and removable whipstocks and other special equipment not a part of the ordinary drilling rig. Dependable well-surveying devices now available permit of observing progress and of determining the position of the hole at all depths. A further development of this practice of "directed drilling" is found in the ability to drill several different wells under one rig, each hole being deflected in a different direction, separately cased and bottomed in the same or different producing horizons.

THE CIRCULATING SYSTEM AND ITS CONTROL

Much depends upon proper functioning of the circulating system in rotary drilling. Prompt and continuous removal of the material loosened by the drill prevents accumulation of the drill cuttings and "freezing" of the drill stem. Deposition of clay on the walls of the well and within the pores of the wall rocks minimizes the tendency of the walls to cave; lubricates the drill pipe, reducing frictional power loss; prevents loss of fluid into very porous, low-pressure formations so that circulating of drill cuttings to the surface will not be interrupted; and seals off high-pressure gas- and water-yielding horizons so that fluids from them cannot enter the well, thus preventing a destructive "blow-out." These are matters of prime importance, and their successful accomplishment requires close control of the volume, pressure and physical characteristics of the fluid circulated.

The circulating medium, as we have seen, is a clay-laden fluid. This fluid, under the propulsion of powerful pumps, is forced through the pump manifold, the flexible hose and swivel and thence down through

the drill stem, passing out into the well just above bottom through holes in the bit. Jetted against the bottom of the hole with high velocity, the circulating fluid is deflected upward and flows back to the surface between the drill pipe and the walls of the well, carrying in the ascending stream the cuttings formed by the drill. At the surface the circulating fluid and drill cuttings are discharged into a wooden or sheet-iron launder or flume of gentle slope, in which the coarser and heavier particles are settled out by gravity. Sand-free mud fluid is discharged from the mud ditch into a mud pit in which surplus fluid is stored, later to be taken up by the pump suction lines for further circulation through the well.

The Mud Ditch and Pit.—The mud ditch is usually a wooden flume about 2 ft. wide and 100 or 125 ft. in length, built around two sides of the derrick, with several right-angle turns (see Fig. 30). Large rectangular settling boxes are sometimes provided at each angle in the flume. The joints are filled with pitch or asphalt to prevent leakage. The slope should be only about 1 ft. between the two ends so that the mud fluid flows sluggishly. The greater part of the length of the ditch is about 1 ft. deeper than the outlet, thus allowing for the accumulation of sand which must be occasionally shoveled out.

The mud pit is often a timber-lined excavation, about 8 by 12 ft. in cross section and 5 to 6 ft. deep. Frequently an ordinary mud pond with sloping earthen embankments is used for storage of fluid. Some operators prefer to use two or three separate pits; one serving as a settling pit, another as a storage pit, and perhaps a third as a pump suction pit.

Sand-separating Devices.—A simple settling ditch, as above described, may not be entirely effective in settling all sand from the mud fluid. Gradually accumulating in the mud pit and in the fluid circulated through the well, this sand may result in freezing of the drill pipe or bit. It has, furthermore, a detrimental scouring effect upon the exposed interior surfaces of the pump, swivel and drill stem. The lubricating and wall-building properties of the clay fluid are also greatly reduced by the presence of appreciable quantities of sand. To effect more complete elimination of the sand and coarse particles in suspension in the mud fluid, some operators resort to the use of mechanical screens or hydraulic classifiers.

One type of vibrating screen that has been successfully adapted to the removal of sand and coarse material from mud fluid used in rotary drilling vibrates at the rate of 1,800 times per minute and is screened with 30- to 60-mesh wire cloth 3 by 5 ft. in size supported at an angle of 15 to 30 deg. from the horizontal. It is placed in the circulating system between the well discharge and the storage pit and may be operated by a 1-hp. electric motor or small steam turbine. Two such vibrating screens are used at each well.

Hydraulic classifiers, sometimes employed in conditioning mud fluid, must be used in conjunction with apparatus for subsequently thickening

the fluid. While effective in removing sand, the method is too complex and equipment is too costly for use at individual wells. It may, however, be advantageously used in large-scale central-plant conditioning of mud fluid, as described in a later section.

The Merco centrifugal separator has been successfully used in removing sand from mud-laden fluid in central reclamation plants. In this machine the centrifuge bowl is 30 in. in diameter and operates at a speed of 540 r.p.m. It is driven by a 10-hp. motor, though the operating load is less than 4 hp. at full speed. The machine has a treatment capacity of 300 gal. per minute, or 10,000 barrels per day. Operating on mud fluid in which the sand content is 40 per cent of all solids present, this machine is capable of removing from 91 to 95 per cent of the sand, though much of it is finer than 150 mesh.

Mud-mixing Methods and Devices.—If clays or soft shales are occasionally penetrated by the drill, the well may furnish its own mud fluid so that little or no attention need be given to preparation of it. More often, there will not be sufficient clay in the formation or it will not be of suitable character to form a satisfactory circulating medium, and clay will have to be brought to the well, perhaps from a considerable distance, and mixed with water to form a fluid of the desired characteristics.

The clay used in preparation of mud fluid may be mixed with the necessary amount of water by simply shoveling it into the mud pit and occasionally stirring the mixture with shovels or hoes. A better plan, however, is to use one or another of the several types of mechanical or hydraulic mud mixers. These may be had from equipment manufacturers or may be constructed from materials commonly available on the producer's lease. One type of mechanical mud mixer consists of a small wooden or steel tank, equipped with either a horizontal or vertical paddle shaft, driven by a chain from a sprocket on the line shaft of the draw works. Another type employs a tank with a wedge-shaped or conical bottom, in which the clay and water are placed and then thoroughly mixed with steam jets directed into the fluid near the bottom. It is reported that steam-mixed mud has certain desirable properties developed to a higher degree than mechanically mixed muds containing the same constituents. Some operators use steam jets for mixing in the mud pit.

Another efficient method of mixing mud fluid, once the solids have been partially hydrated, involves forcing it through jets under pump pressure and spraying it out over the storage sump. Continued circulation in this way will prevent settling of clay from surplus fluid stored in the mud pit and maintain uniformity in the fluid delivered to the pump suction lines.

Community Mud-mixing Plants.—Mud fluid is generally mixed in pits, tanks or mechanical devices situated at or near the well, in which the fluid is to be used, but in some cases, where a number of drilling

operations are under way simultaneously, central plants have been provided at which mud fluid is prepared in sufficient quantity to meet the requirements of several or perhaps many wells. At one community mud-mixing plant in the Ventura field of California, clay mined with steam shovels is moved by motor trucks to a near-by crushing and hydrating plant. It is first passed through a pair of crushing rolls. The crushed clay is then puddled with water, washed through a vibrating screen and sluiced into large tanks where the clay is allowed to hydrate for several days, with occasional agitation by pumping from one tank to another. Well-seasoned clay fluid, somewhat thicker than required in service, is then pumped through pipe lines to the drilling wells, where it is diluted to the desired consistency. A tank full of fresh clay fluid is kept in storage at each well where it will be available in time of emergency.

A large central plant for reclaiming and conditioning "gas-cut" and sand-laden mud fluid is also in service in the Ventura field. Fluid that was formerly discarded at considerable expense now flows through wooden flumes to the reclamation plant where it is first diluted with about four times its volume of water in Dorr bowl classifiers. Dilution releases the suspended fine sand, gas and oil, and the mud fluid is then restored to proper density and viscosity by treatment in a large Dorr traction thickener. Reclaimed mud, stored at the plant in large tanks, is pumped to the wells, the mud distributing lines being maintained under pressure so that a valve has merely to be opened at any of the wells to receive an ample supply of fresh fluid. This plant is capable of conditioning 10,000 bbl. of mud fluid daily and serves as many as 20 drilling wells. From 20 to 70 tons of fine sand are removed from the fluid treated each day, the percentage of sand in the fluid returned to the wells being generally less than 2.

Functions and Properties of Mud Fluid Used in Rotary Drilling.—In its flow through the circulating system the mud fluid has a variety of different functions to perform. It must carry all of the drill cuttings from the bottom of the hole to the surface and discharge them into the settling ditch. It must absorb heat generated by the drilling bit in cutting through the rock formation, and heat generated in the drill pipe by frictional contact on the walls of the well. To prevent caving, it must deposit clay in the wall rocks of the well, aided by the plastering action of the drill pipe. It must seal the pores of sands yielding high-pressure gas or water which might prove troublesome or dangerous in drilling and shut off unusually permeable, low-pressure formations, fissures or crevices into which the fluid might flow in sufficient quantity to cause loss of circulation. By its weight, it must be capable of providing sufficient hydrostatic pressure to prevent high-pressure gas, oil or water from entering the well.

To fulfill these requirements satisfactorily, the mud fluid used should develop maximum plastering action, the solid particles should be capable of remaining in suspension for a long period of time without tendency toward rapid settling and it should be relatively free from sand. It must have a sufficient density to provide the necessary hydrostatic pressure to resist the highest gas, oil and water pressures that may be encountered. It must have sufficient density and viscosity to hold the drill cuttings

in suspension with minimum tendency to settle out. However, the viscosity should not be excessive, otherwise an unduly difficult pumping problem may be created. These properties are secured only by careful selection of the clay used in preparation of the mud fluid. Different types of clay vary widely in their properties, and fluids prepared with them vary correspondingly. Clays satisfactory in every particular for this purpose are not plentiful and must often be brought into the oil fields from remote deposits at considerable expense.

The properties of the fluid circulated will depend upon the conditions to be contended with in the well at the time and the objectives sought. If the objective is merely to circulate drill cuttings to the surface, a fluid weighing about 70 or 75 lb. per cubic foot (10 lb. per gallon) and having a viscosity of 10 to 15 centipoises may be used. If we wish to seal off a porous, low-pressure sand that is absorbing the well fluid, or wish to rapidly deposit clay on the walls of the well to reduce caving tendencies, we may add more clay to produce a fluid having a density as high as 85 lb. per cubic foot (11.4 lb. per gallon) and a viscosity of as much as 25 centipoises. If high-pressure gas encountered in drilling shows a tendency to enter the well, the density of the fluid must be increased as much as possible, but the viscosity should be kept low so that any gas which does enter the circulating system may readily free itself from the fluid after it reaches the surface. Barite and hematite, because of their high densities, are frequently finely ground and added to rotary mud fluid to increase density when high-pressure gas must be contended with. Increase in density without comparable increase in viscosity is thus achieved. Mud fluids weighted with heavy minerals may weigh as much as 135 lb. per cubic foot (18 lb. per gallon). Bentonite and varieties of kaolin, having plastic and colloidal properties developed to a high degree, are frequently added to ordinary mud fluids to assist in holding coarse sand in suspension in the well fluid and to reduce the frictional drag of the drill pipe on the walls of the well.

Action of the Circulating Fluid in Removing Material Loosened by the Drill.—In elevating drill cuttings from the bottom of the well to the surface, effective action of the circulating fluid depends chiefly upon its rate of flow but also upon its density and viscosity. The size and density of the drill cuttings are also important factors. High density and viscosity of the fluid and rapid ascending velocity tend toward efficiency in operation. Fine pulverizing of the material to be elevated also promotes efficiency.

A sand particle tends to sink in water at a rate which increases with its density, the rate of sinking being an expression of the difference between the weight of the sand particle and that of an equal volume of water. The size of the particle also influences the rate of sinking, since the smaller particles present relatively more surface in comparison with their mass and therefore encounter more fluid resistance in sinking. In mud-laden fluid the sand particle will sink more slowly than in water because of the greater density and viscosity of the mud fluid, but its movement is governed by the same physical laws. If now we are to raise this falling particle by giving upward motion to the fluid through which it is sinking, we must circulate the fluid at a more rapid rate than that at which the particle sinks, and the net upward movement of the particle will be represented by the difference between these two rates of movement. When the circulating fluid in the well ascends with the cuttings from the drill, the latter are constantly sinking through the well fluid, but they rise to the surface because the fluid rises more rapidly than the cuttings sink. However, small particles will rise more rapidly than large particles of the same density, and for particles of the same size those having the lower specific gravity will have the more rapid ascending velocity. In other words, the circulating fluid exercises a selective action on the material loosened by the drill, and it is conceivable that at a certain rate of circulation, with material

of variable size and density in the well, the coarser and heavier material might remain on bottom or in suspension in the well fluid, only the lighter particles reaching the surface. In time the heavier and coarser material may accumulate in the well to such an extent that the drill pipe becomes "logy" and tends to freeze in the hole. The remedy is more rapid ascending velocity, which is achieved by operating the pumps at a more rapid rate.

The circulating fluid is discharged from the drill pipe into the well through holes in the drill against the bottom of the hole and is deflected upward, carrying the drill cuttings in suspension. The force developed by from sixty to several hundred gallons of fluid per minute, jetted through relatively small openings only a foot or two off bottom, is probably sufficient to keep the bottom of the hole free of all but the coarser broken material. Many believe that the force of these jets of mud fluid assists in excavating material, particularly when working in the softer formations. Owing to the rotation of the bit, the fluid assumes a swirling, helical motion on rising from bottom, which further assists in lifting the drill cuttings. The path of travel of the cuttings is longer because of this motion and therefore less force is required than if they had to be lifted vertically upward.

The more rapid the progress in drilling, the greater must be the speed of the pumps. This becomes apparent if we consider that energy proportional to the weight of material broken must be expended in lifting it to the surface. For every foot of hole 10 in. in diameter, drilled in average sedimentary rocks at a depth of 5,000 ft. we must theoretically expend upward of 400,000 ft.-lb. of energy in lifting the drill cuttings to the surface. Considering slippage or sinking of the solid material through the fluid on its way out, and general inefficiency of application of the energy in this method of elevation, we must actually expend considerably more energy than this. Obviously, at times when the drill is making hole more rapidly than usual, we must expend more energy in lifting cuttings, and this is accomplished by operating the pump at higher speed thus circulating a greater volume of fluid per unit of time.

The ascending velocity of the fluid keeps the drill cuttings moving toward the surface as long as circulation in sufficient volume is maintained. Should circulation be interrupted, however, as will happen when the power fails or when it is necessary to withdraw the drill stem, coarse and dense material in suspension in the fluid in the well will at once begin to settle toward bottom, perhaps accumulating in sufficient quantity about the bit and drill collar to freeze it to the walls or to make it difficult to reestablish circulation. As a safeguard against difficulty of this character it is important that the mud fluid be of such consistency as to prevent rapid settling of the suspended solids. High viscosity is advantageous in holding the solids in suspension. Well-developed colloidal properties also insure a minimum rate of settling.

Some clays have colloidal tendencies so far developed that within a short time after coming to rest mud fluid containing them tends to form "gels," practically coagulating so that a permanent suspension of all solid particles results. Subsequent agitation, effected by restoration of circulation, will again convert the gelled clay to a fluid condition. A high grade of bentonite, available on the market under the trade name of Aquagel, especially processed for use in rotary drilling, has these desirable qualities developed to a high degree and is frequently used as an addition to the circulating fluid at times when a highly colloidal condition would be especially advantageous. Such highly colloidal materials, in addition to reducing the rate of settling of suspended drill cuttings when circulation is interrupted, also improve the pore-sealing and wall-building properties of the fluid, reducing the tendency of unconsolidated wall rocks to cave and reducing the friction between the drill stem and the walls of the well.

Action of the Circulating Fluid in Sealing Porous Formations and Wall Building.— The extent to which the circulating fluid will deposit clay on the walls of the well and

within the pore spaces and crevices of the wall rocks, depends upon the percentage of solids present in the fluid, upon its colloidal condition, the condition of the walls, the rate of flow and the pressure conditions in the well and within the formations exposed in the well. Heavily laden fluid of low colloidal value, sluggish in its flow, will deposit its clay on the walls of the well more rapidly than when there is comparatively little solid material of high colloidal properties in suspension, or when a rapid rate of flow is maintained. Too rapid flow will erode away loosely consolidated material exposed in the walls. High differential pressure between the well and the surrounding formation encourages movement of fluid from the well into the formation, causing fine particles of clay in suspension in the fluid to enter crevices and pore spaces through which flow occurs, eventually closing them so that they become permanently sealed against movement of fluid either from or into the well. Smooth-surfaced walls offer less opportunity for clay deposition than do exposed surfaces that are irregular and rough.

A certain proportion of the clay in the circulating fluid tends to remain in permanent suspension, and this ordinarily will not be deposited. Any clay deposited on the walls of the well must be in addition to the amount which remains permanently in the fluid. Accordingly, when it is particularly desired to deposit mud on the walls of the well, the driller thickens the fluid in the mud pit. More clay must be continually added if the mudding process is to be continued, for the fluid will soon drop its surplus clay and come to a condition of equilibrium. It should be noted that the volume of clay necessary to plaster the walls of the well will vary directly as the diameter of the hole, that is, the wall area exposed per foot of depth in a 12-in. hole is double that of a 6-in. hole. Deposition of mud on the walls of the well is greatly aided by the plastering action of the eccentrically revolving drill stem.

The amount of clay carried by the fluid in this condition of equilibrium varies with the nature of the clay (as explained above) and also with the rate of flow. The amount of clay that may be carried in the well fluid without deposition increases as the velocity of flow increases, a factor directly dependent upon the speed and capacity of the pumps and upon the cross-sectional area between the drill stem and the walls of the well. It follows that if heavy deposition of clay is the object sought, the speed of the pumps must be reduced until a suitable rate of flow is attained. If a slush pump delivers 100 gal. of fluid per minute through a 6-in. stem working in a 10-in. hole, the rate of flow as the fluid ascends through the well will be about 44 ft. per minute. With a 4-in. stem in a 7-in. hole and the same delivery capacity of the pump, the rate of flow will be about twice as great. The fluid will carry a much higher percentage of clay at the higher speed without deposition than at the lower. By varying the speed of the pumps, a nice adjustment of the rate of deposition to suit any condition is possible.

The pressure maintained upon the fluid is also a factor in determining the rate of deposition, since it is only by excess of pressure in the well fluid, in comparison with that in the formations penetrated, that the fluid is able to enter the formation. When drilling in porous rocks, there is a measurable loss of volume in the well fluid which can only be accounted for on the assumption that the porous rock has absorbed the lost volume. When mud is absorbed by the formation, the clay undoubtedly follows the water into the crevices and pores of the rock to some extent. As it does so, however, the openings through which the mud flows gradually become clogged, until eventually they become impervious to the passage of fluid and the formation is effectively sealed. The extent to which clay penetrates the rock varies with the porosity of the rock and the excess of pressure applied. Experiments conducted by Knapp* indicate that the mud is deposited primarily on the wall surfaces and that penetration seldom exceeds 1 or 2 in. Tests made by the Standard Oil Company of

* Knapp, A., Action of Mud-laden Fluid in Wells, *Trans.* Am. Inst. Mining Met. Eng., vol. 69, pp. 1076–1100, 1923.

California, however, have shown a penetration of as much as 12½ in. with a pressure of 1,200 lb. per square inch.[10] In close-grained rocks, the clay deposit is probably almost entirely on the rock surface, but with the more porous rocks it seems reasonable to expect that it penetrates to a distance of at least several inches. In strata thought to be traversed by well-developed channels, the mud has in some cases appeared in wells several hundred feet distant from that into which it was pumped, proving that a considerable and fairly rapid migration through the formation is possible under favorable conditions. Loss of fluid during circulation is a direct measure of the pressure conditions within, and the permeability of, the strata penetrated; and drillers are in the habit of watching the depth of fluid in the mud pit as an indication of the nature of the rock in which the drill is working.

In cases where low-pressure "thief" sands absorb well fluid so rapidly that circulation back to the surface cannot be maintained, drilling must cease until such time as the highly permeable horizon is sealed off and circulation back to the surface is restored. At such times the mud fluid is loaded with the maximum amount of clay that the pumps can handle, and, if the condition still persists, cottonseed hulls, sawdust, wood shavings, cereals or other light, absorbent solids and jellying substances may be added to the fluid. About 4 per cent of Aquagel is carried in the well fluid by several California operators at such times.

Various chemical reagents are sometimes added to the mud fluid to develop special properties useful in sealing highly permeable formations. Sodium aluminate is the base of one chemical reagent marketed for this purpose, one part of the reagent being used with each 600 parts of mud fluid, by volume. Hydraulic lime, caustic soda, soda ash and sodium silicate are similarly used. These and other alkaline reagents react with clay, forming gelatinous precipitates which accumulate on the surfaces of the clay particles, causing them to adhere. Theoretically, clays are deflocculated by the addition of alkalies and will tend to flocculate on addition of acids. It has been suggested that alkaline reagents be used in the treatment of gas-cut muds, which theoretically should cause deflocculation and release of the gas bubbles. In practice, however, soluble salts may be present in the water phase of the fluid, which will react with alkaline reagents forming gelatinous precipitates which tend to increase rather than decrease viscosity and tendency to gas-cut.

Action of the Circulating Fluid in Offsetting High Fluid Pressures Encountered in Formations Penetrated in Drilling.—Effective application of the circulating fluid in controlling high-pressure gas, oil and water encountered in drilling depends not only on its ability to seal the pores of the rock but also upon the resisting hydrostatic pressure that can be developed to prevent extraneous fluids from entering the well. Here density of the fluid is important, the hydrostatic head at any depth increasing directly with the specific gravity of the fluid. Mud fluids of such density and viscosity as can be conveniently pumped, containing clay alone as the solid medium in suspension, are capable of developing hydrostatic pressures as great as 0.59 lb. per foot of depth (85 lb. per cubic foot). This will be sufficient to offset the highest pressures ordinarily encountered in drilling; but occasionally, when an abnormally high gas pressure must be contended with, a heavier fluid will be required. At such times the circulating fluid may be weighted with finely ground barite ($BaSO_4$), siderite ($FeCO_3$) or hematite (Fe_2O_3), forming fluids developing a hydrostatic head as great as 0.94 lb. per foot of depth (135 lb. per cubic foot) and yet having a viscosity such that it can be readily handled by the pumps. Hydrostatic pressures of about 0.7 lb. per foot of depth represent the maximum that have been found necessary in practice.

Ordinary clay has a specific gravity ranging from 2.0 to 2.7, depending upon its composition and condition; that of barite is 4.2 and that of hematite, 5.2. Though of lower density than hematite, barite is generally preferred as a weighting material to

hematite. Some varieties of hematite are gritty, causing rapid abrasion of pump liners, swivel and drill pipe, and the material promotes oxidation of any iron or steel with which it comes into contact. Finely ground barite, prepared for use as a mud-weighting material and containing about 5 per cent of Aquagel is marketed under the name of Baroid. Anything up to 95 lb. of Baroid may be added to each cubic foot of fluid, depending upon the amount of clay present and the density desired. When used for weighting mud fluids, heavy minerals must be ground so that upward of 90 per cent will pass a 200-mesh screen, and some authorities maintain that it is preferable if a large percentage will pass 300 mesh. If too coarse, the material tends to settle rapidly when the fluid is at rest.

If a high-pressure gas sand is being penetrated by the drill and there is not sufficient hydrostatic pressure developed in the well to offset the gas pressure, it will tend to enter and flow to the surface occluded in the mud fluid. In such cases the gas is often in the form of finely divided bubbles, expanding to form a froth as the fluid approaches and is discharged at the surface. There is occasionally so much gas entrained in the fluid as to reduce its density seriously. As a result, the differential pressure between the formation and the well is further increased: more gas enters, perhaps in sufficient quantity to violently expel the fluid at the surface. Gas-cut mud often does not readily release its gas in the mud ditch and storage pit at the surface, particularly if the fluid is overly viscous. In such a case the fluid must either be discarded or treated in some way to release the entrained gas. This may be accomplished by passing the fluid through a screen or by adding water to reduce the viscosity, subsequently thickening the fluid to proper density after the gas is released. Gas reaching the surface in the mud fluid does not necessarily indicate that insufficient pressure is being maintained to prevent the gas from entering the well from the formation. It may merely be such gas as is stored in the pores of the material pulverized by the drill. Though the volume of such gas in its place of storage is small, owing to its high pressure, it is capable of expansion to a volume sufficient to alter seriously the characteristics of the circulating fluid.

Action of the Circulating Fluid in Absorbing Heat.—When a steel bit is revolved against a rock face with sufficient pressure literally to tear the rock apart, a great deal of energy is expended and necessarily heat is generated. Furthermore, this work is done in a confined space in a material originally under a temperature of from 60 to 200°F. so that there is little opportunity for natural conduction of heat away from the center of action. The greater the bit pressure and the more rapid the rate of drilling, the greater will be the heat generated. Were it not for the circulating fluid, the drill would in a few minutes become so hot as to suffer serious loss of its wear-resisting qualities. One of the important functions of the circulating fluid is that of absorbing this heat and conducting it away. There is doubtless also considerable heat generated by stress in the drill pipe and by its continual friction on the walls of the well. This heat is also absorbed by the circulating fluid.

The mud fluid enters the well at about atmospheric temperature but quickly begins to absorb heat as it travels down through the drill pipe. In one sense the circulating system is like a heat exchanger, the cool descending fluid within the drill pipe absorbing heat from the warm ascending fluid about it. The ascending fluid is heated not alone by absorption of heat from the drill pipe and bit but also by absorption of formational heat. The important center of heat generation is of course reached at the drilling bit, and in order to bring the cooling fluid into close contact with the cutting edge, it is discharged through holes in the side of the bit just a few inches above. These holes are small in comparison with the cross section of the opening through the drill pipe, hence the flow velocity is greatly increased at this point. The fluid, under high pressure and moving with high velocity, is jetted directly against the bottom of

the hole and is deflected upward, assuming a swirling, helical upward flow that must be quite effective in absorbing heat developed in the bit and drill pipe; but any interruption in circulation will quickly cause trouble if the bit is continued rotating on bottom.

Ability of the circulating mud fluid to absorb heat is determined by its specific heat, by the temperature at which it is supplied and by the weight of fluid circulated per unit of time. Pure water has a higher specific heat than clay, hence we obtain maximum cooling effect with fluids containing small percentages of clay, supplied at low initial temperature and in large volume, that is, at high flow velocity.

POWER REQUIREMENTS AND POWER EQUIPMENT IN ROTARY DRILLING

The cost of power equipment represents an important part of the total cost of a rotary rig, and the power cost of operating it is always an important element in total drilling cost. The power requirements in different phases of the work are extremely variable, ranging from only 20 hp. to as much as 375 hp. with the heavy equipment used in deep drilling. Power requirements in all phases of the work increase with depth. There must be considerable stand-by power capacity through the provision of power equipment capable of satisfying a maximum demand considerably in excess of normal requirements, or the power equipment must be capable of sustaining a considerable overload for brief periods of time in meeting the excessive demands that are occasionally created. Steam is found to be the most flexible form of power in meeting variable requirements and is more widely employed in operating rotary equipment than any other. Electric power is frequently used, however, and though less flexible than steam power, possesses certain advantages. Where available, it often results in over-all reduction of power expense. Internal-combustion engines have been used in driving rotary equipment only to a limited extent, but engines of the Diesel or semi-Diesel type would appear to have possibilities of successful and profitable application, particularly in exploration work in localities remote from electric power or fuel supply. When directly applied, this type of prime mover is considerably less flexible in its speed and power characteristics than either the steam engine or the electric motor, but the Diesel electric drive using direct-current motors has been shown to be well adapted in experimental tests.

The power consumed in operating a rotary rig is used primarily in three different phases of the work: (1) rotating the drill stem, (2) operating the circulating pumps and (3) drawing out the drill stem when it is necessary to change bits. The first two of these functions draw upon the source of power simultaneously. When hoisting operations are in progress, the other two functions are non-operative. In addition to these primary power-consuming operations, there are occasional minor operations, such as handling and making up drill pipe and casing, operating mud-mixing appliances, special pumps used in cementing, etc. In addition to power usefully employed, there is often a considerable

stand-by loss and transmission losses are in many cases an important percentage of the total power consumption.

The power consumed in rotating the drill pipe and bit on the formation represents but a small part of the total power expended at a normal rotary drilling rig. The power consumption in this phase of the work is almost constant, varying but little with depth or with the size of the drill pipe and bit. At two California wells drilled to a depth of 7,000 ft. the average power consumption in rotating the drill pipe and bit was found to be about 20 or 25 hp. The maximum load only occasionally reached 39 hp.

In operation of the circulating pumps, there is naturally a considerable variation in power consumption. Changes in depth, variation in clearances between the drill pipe and the wall of the well, in the size of the drill pipe used, in the mud viscosity and density, in the volume of fluid circulated and pressure conditions maintained, combine to create an extremely variable power load. The necessary pressure and power increase rapidly with depth, though the volume of fluid circulated diminishes. Studies made in the Ventura field of California show that the circulating pressure gradually increases with depth to a maximum of 700 lb. per square inch at about 7,000 ft., while the volume circulated diminishes from 50 to 25 cu. ft. per minute. Under these conditions about 90 hp. is required to operate the pumps at a depth of 5,000 ft. and 130 hp. at 6,000 ft. where the maximum power consumption is reached. Necessary pump pressures seem to increase uniformly at a rate of about 100 lb. per 1,000 ft. of depth.

The power consumed in hoisting operations increases with the weight of drill pipe handled and with the speed of hoisting. Weight increases with the depth of the well and with the size of the drill pipe in use. The weights of columns of drill pipe used in drilling wells to between 7,000 and 8,000 ft. have reached as much as 100 tons. The heavier loads are necessarily hoisted at slower speed. More lines are strung on the hoisting block to increase the mechanical advantage of the hoisting equipment and this reduces the speed of hoisting. The driller also utilizes the several gear ratios afforded by the draw works in adapting the available power to the loads imposed. The actual speed at which the drill pipe is lifted in hoisting operations therefore varies greatly. With a long heavy column of pipe in the well, the hoisting speed may be only a small fraction of that with which the last few joints are handled when the bit is nearing the surface. A maximum power consumption of 245 hp. has been noted in hoisting drill pipe in one instance where 4,000 ft. of 6⅝-in. drill pipe was being lifted with eight lines, a three-speed draw works and a 12- by 12-in. engine. It is apparent that hoisting operations are responsible for a large part of the total power consumption of a rotary-drilled well,

and that the power equipment may at times be taxed to its limit of capacity in this phase of the work.

Power Correlation of Rotary Drilling Equipment.—For smooth functioning of the rotary equipment, it is important that the size, capacity and power consumption of the several parts of the rig be properly proportioned. Circulating pumps, too small in capacity or incapable of delivering fluid to the well at sufficient pressure, will fail to maintain the fluid in the well in proper condition and reduce the rate of progress that an otherwise well-equipped rig would be able to attain. Insufficient flexibility in speed and mechanical advantage afforded by the draw works will

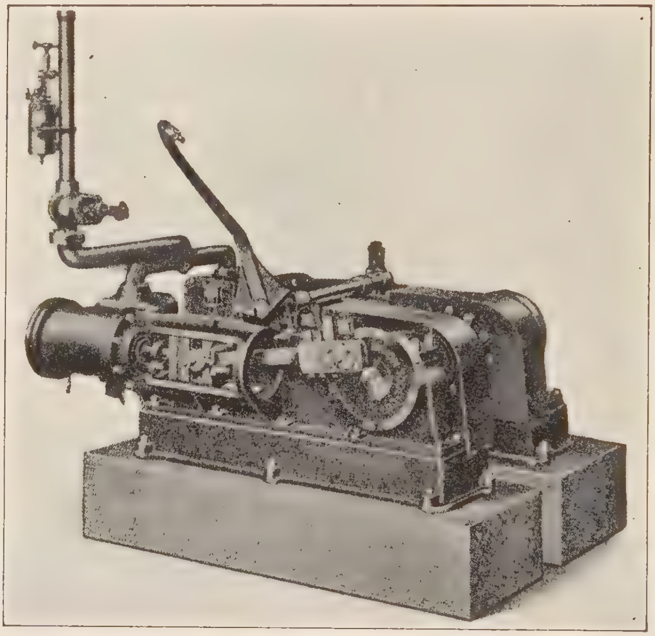
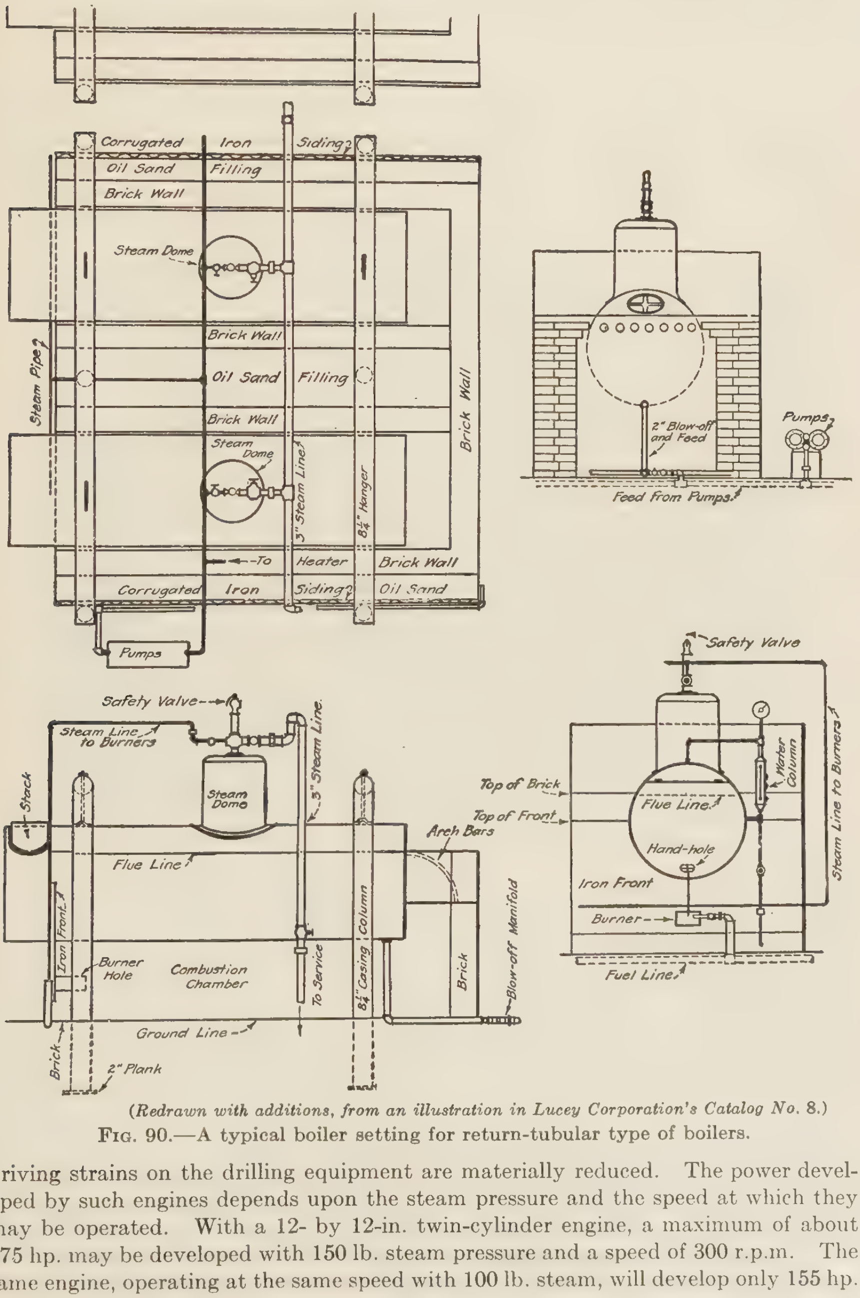


FIG. 89.—"Ideal" twin-cylinder steam drilling engine.

greatly retard the speed of hoisting drill pipe. A flexible and powerful draw works and heavy-duty pumps will not attain their highest efficiency if handicapped by an inadequate power plant. The size and weight of the derrick, rotary crown blocks, hoisting blocks, hoisting cable, swivel, drill stem and minor parts of the rig must be proportioned to the loads imposed and the power to be transmitted. The depth to be attained in drilling will be a controlling factor in determining the weight and power requirements of various parts of the rig. In heavy-duty rigs now available on the market, every part is designed for efficient functioning and proper correlation with other parts to depths as great as 10,000 ft.

Steam Power Plant for Rotary Drilling.—The steam engines used at most rotary rigs are of the duplex, twin-cylinder type, usually with cylinders 12 in. in diameter and

a 12-in. piston stroke (see Fig. 89). For lighter service, 10- by 10-in. engines of the same style are used. In engines of this type the cranks are set "on quarters," so that there are no dead centers and the flywheel characteristics of the one-cylinder engine may be eliminated. With this type of engine, a more uniform pull is delivered and



(*Redrawn with additions, from an illustration in Lucey Corporation's Catalog No. 8.*)

Fig. 90.—A typical boiler setting for return-tubular type of boilers.

driving strains on the drilling equipment are materially reduced. The power developed by such engines depends upon the steam pressure and the speed at which they may be operated. With a 12- by 12-in. twin-cylinder engine, a maximum of about 275 hp. may be developed with 150 lb. steam pressure and a speed of 300 r.p.m. The same engine, operating at the same speed with 100 lb. steam, will develop only 155 hp.

A 10- by 10-in., twin-cylinder engine develops a maximum of 150 hp. at 150 lb. steam pressure and a speed of 350 r.p.m.

Under the best conditions possible, such engines will consume from 30 to 40 lb. of steam per horsepower-hour. With only one-quarter full load the figures may be nearly doubled, and with poor general mechanical conditions, characteristic of many oil-field installations, the steam consumption may rise to upward of 100 lb. per horsepower-hour.

The boilers used in steam generation may be either the fire-tube, water-tube, locomotive or Scotch marine types. Probably the most common type met with in the oil fields is the horizontal-return, fire-tube type, generally mounted on brick supports above a brick fire box (see Figs. 90 and 91). Many operators, however, prefer the locomotive type in which a water-jacketed, metal fire box is riveted directly to the boiler shell (see Fig. 92). This boiler is especially useful for temporary service,

FIG. 91.—A typical field installation of return-tubular boilers.

as in drilling, since it requires less in the way of masonry supports than other types and can be quickly moved and set up in a new location.

Selection of boiler sizes and weights is conditioned by difficulty of transportation. Seventy-horsepower boilers designed for 175 lb. working pressure and 85-hp. boilers designed for 200 lb. steam pressure are widely used in rotary drilling service, these being sizes that can be conveniently transported over the roads usually provided and with the facilities usually available. Larger sizes used in some regions are the 100-hp. boiler designed for a working pressure of 200 lb. and the 125-hp. boiler designed for working pressures up to 325 or 350 lb. Many operators are using boilers designed for a maximum of 150 lb. working pressure, but with normal transmission losses this boiler pressure allows only from 115 to 135 lb. working pressure on the engine and pumps. Many mid-continent operators are showing a preference for higher steam pressures, some specifying boilers designed for 350 lb. steam pressure. High-pressure boilers have the advantage of a greater volume of steam reserve, that is, greater steam storage capacity for peak-load requirements. However, there will ordinarily be

greater losses between the boiler and the engine with high-pressure than with low-pressure steam.

The maximum steam consumption of a heavy-duty rotary rig is about 300,000 lb. daily. Oil-field boilers will evaporate about 6 lb. of water per hour for each square foot of heating surface, and it is customary in tubular boilers to allow about 15 sq. ft. of heating surface for each rated horsepower. At this rate two 85-hp. boilers should be sufficient for one drilling rig, but, because of inefficiencies in operation, peak-load requirements and high transmission losses, three or four are usually provided.

Considerable increase in efficiency and economies in fuel consumption are attained through the use of feed-water preheaters and condensers. Fuel requirements may be reduced from 10 to 15 per cent and water consumption decreased 20 to 25 per cent,

Fig. 92.—A typical field installation of locomotive-type boilers.

while the boiler capacity may be increased as much as 10 to 16 per cent. Other advantages also accrue through extension of the life of the boilers and lower maintenance costs. Several different types of preheaters are finding use in oil fields in connection with drilling operations, but the "open type" is preferred by most operators. Economies in fuel consumption and smaller transmission losses may also be realized through proper insulation of boilers and steam piping. Increased efficiency in steam generation, transmission and application through the use of superheaters is also engaging the interest of oil producers.

Electric Power Plant for Rotary Drilling.—Where electric power is available for drilling operations, it offers certain definite advantages that during recent years have led to its increasing use in competition with steam. If the motor selected is sufficiently large, an abundant reserve of power is available for the maximum demands that may be made. Under favorable conditions, progress in drilling may be more rapid and the unit cost may be lower than with steam. There are no cold-weather delays. The control devices provided afford the wide range of speed characteristics required for various operations. Electrical equipment is easy to transport, install and maintain, and problems of water and fuel supply are eliminated.

The motors used for rotary drilling are of the single-speed, variable-speed, wound-rotor, induction type which, through the use of suitable control equipment, is reversible and can be operated over a wide range of speeds to adapt it to variable speed and load requirements. The induction motor can be operated at reduced speeds and it can be made to vary its speed as its load varies, the extent of this variation being regulated by a controller and resistor. Drilling motors can exert a very high pulling torque, and their ability to do so in an emergency is often important. The motor increases its pull automatically as the load increases, without any changes or adjustments, and develops its maximum pull at dead stall. Motors of this type usually operate at speeds of 720 to 900 r.p.m. on 60-cycle circuits and at 600 to 750 r.p.m. on 50-cycle circuits. Current is supplied at 440 volts. Both eight- and ten-pole motors are used, but ten-pole machines are in the majority.

The size of motor selected will depend upon the size and weight of the rig to be operated and the depth to be attained in drilling. Motors of 75 and 150 hp. have been widely used, and, for recent deep drilling, motors of 250 hp. capacity have been specified. Properly geared to the draw works, a 75-hp. motor will meet all requirements to a depth of 3,500 or 4,000 ft., but for greater depths, up to about 7,000 ft., the 150-hp. motor is necessary. The 250-hp. motor is capable of conducting drilling operations up to a depth of 10,000 ft.

A motor capable of handling the heavy hoisting loads in rotary drilling will operate inefficiently under the comparatively light duty of rotating the drill stem. This inefficiency becomes particularly important in large motors used in deep drilling. For such conditions, the "star-delta," dual-torque motor is well adapted. Such a motor is equipped with special winding that permits it to operate efficiently at half normal load. By simply pressing a button or throwing a switch, which changes the connections on the leads extending out from the motor, a motor capable of delivering 250 hp., is converted to an efficient 125-hp. motor. The higher power is used for hoisting purposes and handling casing and other heavy loads, while for rotating drill stem, making up drill pipe and other light duties the motor operates efficiently on the 125-hp. circuit. In either case a considerable overload is possible for short periods of time without overheating. This is especially important when hoisting long strings of heavy drill pipe.

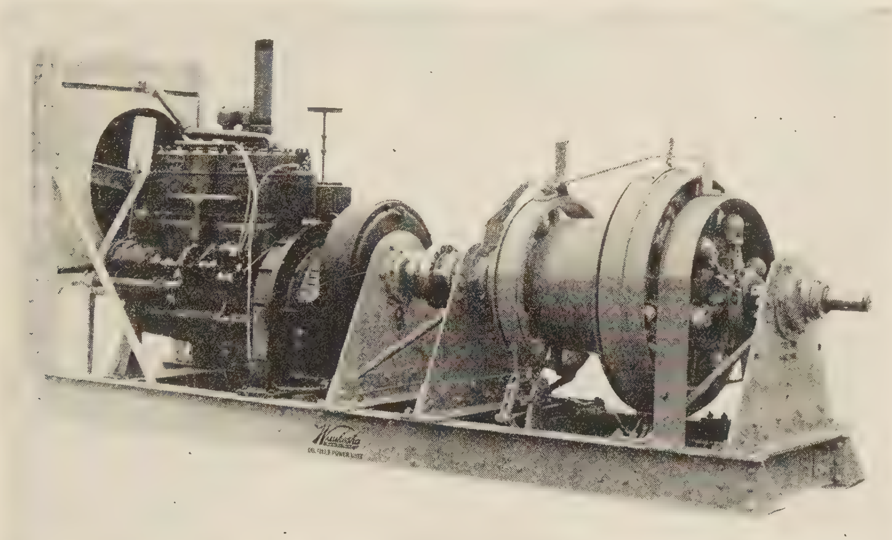
The speed of the drilling motor is controlled by adjusting the amount of resistance placed in series with the secondary or rotor winding of the motor. This adjustment is accomplished magnetically through a bank of grid resistors, regulated by a multipoint master controller which also provides for reversal of the motor. Often an auxiliary controller is also supplied, which affords a means of inserting high resistance in the secondary circuit of the motor, thus varying the speed for each point of control on the master controller. One design affords 10 points of speed control on the master controller and 9 on the auxiliary, thus providing 90 different speeds. This is more than is necessary in rotary drilling, and the auxiliary controller is often omitted. The controls are usually operated by an endless wire strand passed over a "telegraph wheel" located on the draw-works post.

Because of the risk of fire and explosion, due to frequent presence of gas about drilling wells, motors are preferably completely enclosed with steel housing, and oil-immersed contactors are used in the control mechanism. Overload relays and oil-immersed circuit-breakers are provided to protect the motor against damage through overheating.

In order to adapt the speed of the motor to that required for the line shaft of the draw works, it is customary to make use of an intermediate single-reduction gear unit. The motor is direct connected to the drive shaft of the gear unit by a flexible coupling, and a chain from a sprocket on the low-speed shaft of the gear unit drives the draw-

works line shaft. The gear ratio in the unit is about $3\frac{1}{4}$:1, giving the drive sprocket a normal operating speed of about 220 r.p.m., or about the same as is ordinarily provided by the drive sprocket of a twin-cylinder drilling engine. The gear unit is usually mounted with the motor on a single cast-iron base. It is preferably equipped with roller bearings and special or alloy steel shafts and gears, the latter being accurately machined and heat treated. The positive splash system of lubrication is often employed. A 100-hp. reduction-gear unit of this type weighs 4,400 lb.

A twin-motor reduction gear makes possible the use of two motors in driving the draw works instead of a single motor. This has its advantages in better adapting the power input to the load requirements. In meeting the comparatively low power requirement of drilling only one motor will be used, the current to the other motor



(*Courtesy of Waukesha Motor Co.*)

Fig. 93.—Vertical automotive type of gas engine with reversing clutch and reduction gear.

being cut off and its armature allowed to idle. For greater speed and power when hoisting long strings of heavy drill pipe, the second motor is cut into the operating circuit. The use of two motors operating in synchronism in this way offers certain advantages over the ordinary variable-speed single motor. The combined efforts of two motors for the heavier operations will reduce motor failures, and, in the event that one motor should fail, continued operation without delay is assured by the second.

Use of Internal-combustion Engines in Rotary Drilling.—While not used to the extent that steam engines and electric motors are employed in rotary drilling, there are instances wherein both gas engines and engines of the Diesel type have found successful application. When gas engines are used, the vertical four- or six-cylinder automotive type is generally employed (see Fig. 93). In the drilling of one 3,361-ft. Oklahoma well, completed in 29 drilling days, three separate gas engines were used, each rated at 300 hp. One of these, used for operating the draw works and rotary table, was connected with the draw-works line shaft through a reversing clutch which provided a speed reduction from approximately 1,000 to 330 r.p.m. An 18-string "Tex-rope" drive was used to transmit power from the reversing-clutch drum to the jackshaft of the four-speed draw works. Each of the two slush pumps was driven by

a separate 300-hp. gas engine. Each pump was connected with its engine through a train of gearing providing a 20:1 speed reduction. The average daily gas consumption for all three engines in the drilling of this well was only 520,000 cu. ft., and the daily water consumption ranged from 150 to 200 bbl.

Diesel engines have been used for drilling purposes only in an experimental way in the American oil fields, though they have been used to a greater extent abroad. In one successful demonstration in the Inglewood field of California, two 200-hp., six-cylinder, four-cycle, full-Diesel engines were connected by V-belt drive to two 225-kw. direct-current generators, which were wired through a control panel to a 250-hp. direct-current motor driving the draw works and two 125-hp. motors of the same type driving the pumps. The 250-hp. motor was direct connected to a reduction-gear unit, the low-speed shaft of which was in turn connected with the line shaft of the draw works by a chain drive. Each of two 6- by 16-in. slush pumps was driven, through gearing, by one of the two 125-hp. motors.

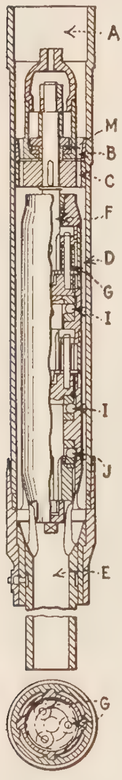


Fig. 94.—Capelushnikov turbo drill.

The Turbo Drill.—The turbo drill designed by M. Capelushnikov and developed and used to some extent in the Russian oil fields is unique in that the drill stem does not rotate with the drilling bit. There is therefore no necessity for the swivel and rotary table. The turbo drill is rotated by the pressure of the circulating drilling fluid on a hydraulic turbine enclosed in a tubular element mounted on the lower end of the drill pipe. The latter serves only to conduct the fluid to the turbine and to apply pressure to the bit. Suitable gearing is provided for reducing the high rotational speed of the turbine to that desired for the bit. The mud pump thus becomes the source of power in operation of the drill, and the power developed depends entirely upon the capacity of the pump.

Figure 94 presents vertical and horizontal sections through the turbine rotor and gear-reduction mechanism. The upper end of the shell *A* is screwed on the lower end of the non-rotating drill pipe through which the drilling fluid is delivered. The fluid is given rotational deflection by the stationary guide vanes *B* before it enters the curved vanes of the turbine rotor *C*. Discharging down around the reduction gear box by way of the annular space *D*, the fluid enters the rotating tube *E* to the lower end of which the drill is attached. The fluid is discharged into the well through holes in the bit and lifts the drill cuttings to the surface in the usual way. The turbine is of the Jonvalle or Curtis hydraulic type, its power being transmitted through the shaft *F* and reduction gears *G* to the vertical tube *E* which emerges through a fluid-tight bushing and gland. The entire reduction gear is hermetically sealed so that the circulating fluid does not have access to its accurately machined gearing. End pressure on the rotating elements is taken up by ball bearing *J* while the gear assemblies rotate on ball bearings *I* and the turbine shaft rotates on ball bearing *M*. Lubricating oil is fed through the turbine shaft and reduction gearing to all bearings by the pressure of a piston actuated by fluid pressure in the head of the turbine unit. From one to three reduction-gear units may be used, affording a range of rotational speeds for the bit of from 25 to 370 r.p.m.

It is claimed that the turbo drill drills straighter holes than is usual with rotary equipment and affords more efficient utilization of power. There is no frictional loss resulting from pressure of rotating drill pipe against the walls of the well. There are fewer twist-offs of the drill pipe and a lighter one may be used. The equipment

is less expensive since the costly rotary table and swivel are eliminated. Owing to the absence of rotating parts in the surface equipment, the accident hazard is reduced.

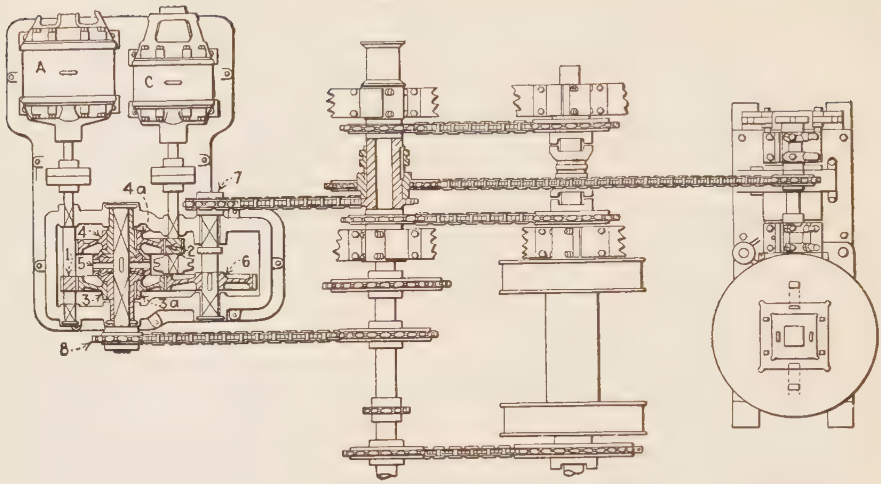
Automatic Feed and Control Devices Designed for Use with Mechanically Regulated Rotary Drilling Equipment

In discussing the mechanics of rotary drilling, the importance of avoiding excessive bit pressure and drill-pipe torque was suggested. Maintenance of proper mechanical conditions is largely a matter of skillful "feeding," or control of the rate at which the hoisting cable is released from the draw-works hoisting drum. Weight indicators, described in an earlier section, assist the driller in maintaining proper operating adjustments, but even with weight indicators in use we are still dependent upon the faithful and skillful performance of his duties by the driller. The driller is not an automaton. During the long weary hours in his position at the control post at the side of the draw works, his attention wavers occasionally or he is engaged in conversation by one or another of his helpers. Now and then he releases the control brake a little, and when the bit pressure works off somewhat he releases it again. The result is that if we set for him a certain maximum bit pressure, the average pressure applied is apt to be considerably less, and his tendency is to exceed momentarily the maximum in order to make faster progress. In other words, hand feeding is generally conducive to fluctuating bit pressures, resulting in erratic operating conditions.

As a means of overcoming the difficulties inherent in the manually controlled equipment, efforts have been successfully directed toward the development of devices for automatically controlling bit pressure and drill-pipe torque. Such devices, by maintaining a constant pressure on the bit, drill straighter holes, make more rapid progress, and there are fewer twist-offs of the stem or other breakages of the drilling equipment. Three such automatic controls have been perfected and have found practical use, these being the Hild differential drive, the Halliburton drilling control and the General Electric automatic weight control. Available space permits of only brief description of these somewhat complex mechanisms.

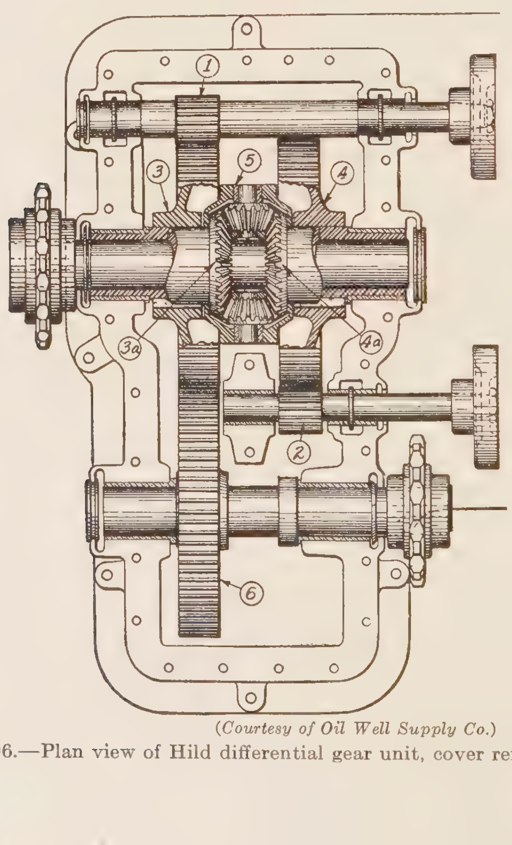
The Hild Differential Drive.—The Hild differential drive comprises a differential reduction gear, somewhat similar in design to that used in automobiles, together with two electric motors, all assembled as a unit which takes the place of the power plant normally provided. Controllers operating through a grid resistance, together with an indicating wattmeter and ammeter, supplement the main unit. Figure 95 illustrates the general arrangement of the Hild drive with respect to the rotary equipment, while Fig. 96 presents a plan view of the differential gear mechanism.

As shown in Fig. 95, the "drilling motor" *A* is connected to one-half of the differential gear 3*a*, and also through gears 1, 3 and 6 and sprocket 7 to the rotary table, while the "regulating motor" *C* is connected to the other half of the differential 4*a*. The hoisting drum of the draw works is actuated by a chain drive from sprocket 8, attached to the central or floating shaft of the differential assembly. The drilling motor in a



(*Courtesy of Oil Well Supply Co.*)

FIG. 95.—General plan showing relationship of Hild differential gear to draw works and rotary table.



(*Courtesy of Oil Well Supply Co.*)

FIG. 96.—Plan view of Hild differential gear unit, cover removed.

large unit suitable for deep drilling is a 75 hp., three-phase, 60-cycle, 440-volt motor, operating at a constant speed of 1,160 r.p.m. The regulating motor is smaller, generally 35 hp., and of the same type and speed as the drilling motor.

When gears $3a$ and $4a$ of the differential rotate in opposite directions at equal speed, sprocket 8 is stationary. When $3a$ and $4a$ rotate in opposite directions at different speeds, sprocket 8 rotates in the direction of the greater speed and at one-half the difference of their speeds. Thus the two motors A and C may run at or near full speed, and by varying the speed of one or the other slightly the hoisting drum of the draw works can be slowly rotated backward or forward. The speed changes of the motors are effected by load variations. Motor A drives in the direction of lowering the drill pipe, while motor C drives in the opposite direction to hoist it. When the brake of the hoisting drum is released, the weight of the drill pipe, tending to rotate the drum, exerts a torque on motors A and C through the differential gear. This will tend to drive motor A somewhat faster. Motor C, on the other hand, will oppose this pull and it will therefore slow down somewhat. The difference between the two motor speeds, thus developed, A being the faster, will permit the hoisting drum to slowly revolve in the direction of lowering the drill pipe. Motor C always tends to lift the drill pipe, even when it is descending, and the power load on motor C is always a measure of the unsupported weight of the drill stem.

The work of motor A during drilling, besides driving the rotary table, is always to lower the drill stem. When motor A has no frictional load, then the effect of the descending weight of the drill stem is such as to produce a negative load, and motor A functions as a generator; that is, it serves as a dynamic, regenerative brake, returning current into the line and assisting in revolving the rotary table. When motor A thus serves as a regenerative brake, motor C takes energy from the supply circuit and motor A, operating as a generator, returns it. Apart from the losses, C and A balance. The kinetic energy of the drill stem in thus lowering itself will be transmitted to help turn the rotary table. Thus, when drilling, the output of both motors and the kinetic energy of the heavy drill pipe are all transmitted to rotate the bit.

When the bit is on bottom, the weight supported by the hoisting drum is diminished by the amount of the weight carried by the bit. Therefore the load on motor C is diminished, and, as the load decreases, its speed increases. Meanwhile, when the bit presses on bottom, motor A, rotating it, receives additional load and tends to slow down. The effect of motor C speeding up and motor A slowing down is to reduce the rate of movement of the hoisting drum, that is, the drill stem is lowered less rapidly. As the load on motor A increases, this downward progress of the drill stem approaches zero; and if the load on motor A becomes still greater, the drill stem will be slowly lifted.

The torsional load on the drill stem depends upon the bit pressure. Hence, with the differential control, the downward progress of the drill is regulated simultaneously and cooperatively by the pressure of the bit and by the torque of the drill stem. By slightly adjusting the motor speeds, a limiting pressure on the bit results, that is, the equipment may be adjusted to maintain any desired bit pressure irrespective of the material in which it operates.

It has been shown that the power input of both motors goes into the work of revolving the drill stem. A wattmeter ahead of both motors and indicating their combined loads will thus give a measure of the load on the drill pipe at any time. This indicating meter may thus be used to keep the driller constantly informed of the formation changes and condition of the bit. By using a recording wattmeter we may secure a graphic story of almost every phase of the drilling work, not only that involved in rotating the bit on or off bottom, but also when "running in" or "coming out" of the hole, making connections, etc. This record is helpful not only to the driller but is also of interest to the superintendent and engineers.

When the Hild drive is used, the driller's duties are exactly the same as before except during drilling. After the bit has been set on bottom, the apparatus set to maintain the desired bit pressure and the table started rotating at proper speed, the driller throws the hoisting-drum brake lever wide open and allows the automatic feed mechanism to take control. He is then free to leave the controls and attend to other matters, such as to supervise mud circulation and incidental repairs to equipment. No human hand is needed at the controls until it becomes necessary to add a length of drill pipe or draw out the stem to replace a worn bit. The Hild drive is highly sensitive, accurate and quick to respond to variations in operating conditions. In addition to a straighter hole and fewer twist-offs, which result from more uniform bit pressure, it is claimed that the Hild drive makes better progress, with fewer interruptions in drilling; that power consumption is reduced; that there is less wear on the drilling equipment, and less skill and attention are required on the part of the driller. The fact that it has as yet been developed to operate only with electric power has to some extent prevented its more wide-spread use. Though well adapted to the work of rotary drilling, electric power is not always available and many operators still prefer steam power.

The Halliburton Drilling Control.—Another device having automatic feeding and controlled bit pressure and drill-pipe torque as its objectives is known as the Halliburton drilling control. Like the Hild drive, described above, this device also makes use of a differential gear, somewhat similar to that used in the rear end of an automobile. It is a compact, chain-driven unit, mounted on heavy steel skids, designed for installation between the draw works and the steam engine, electric motor or internal-combustion engine used as a source of power. Several types are available, one or another of which is adaptable for use with any three- or four-speed draw works.

An understanding of the automobile differential gives a clear insight into the reason for using the differential as a means of controlling the weight on the drilling bit. The function of the differential of the automobile is to permit of a flow of power necessary for each of the two rear wheels, which are often operating at different speeds. In the same way, a division of the power and two available speeds are obtained from a single power unit when the differential drilling control is used, one of which is employed in operating the rotary table, while the other is applied to the hoisting drum of the draw works. The relative amounts of power apportioned to the hoist and rotary table depend upon the relative resistance encountered in each mechanism. The greatest torque that can be safely transmitted to the bit is evenly and continuously employed. When the bit encounters a drilling load which its portion of the power will not handle, the other half of the differential applies power to the draw works and lifts the drill pipe and bit so that less bit pressure is exerted. As the resistance to the bit is relieved, the stem is again lowered and the bit continues making hole. The control is entirely automatic and the driller is relieved of all hand feeding.

The General Electric Automatic Weight Control.—Another device designed to provide automatic feeding and positive bit-pressure control has been developed by the General Electric Company. This comprises a two-speed, motor-driven hoist, which operates on the "dead end" of the hoisting cable. An auxiliary resistor control and switch panel must also be provided. The action of the motor is governed by a weight indicator of the Martin-Decker type (see p. 220) and is so designed that when the weight bearing on the bit is greater than an amount for which the apparatus may be set, the stem is automatically lifted off bottom. If the bit pressure is less than the maximum permitted, the apparatus automatically lowers the drill pipe at a rate which varies inversely as the bit pressure. The feeding and retrieving action of the device is thus automatically responsive to the weight imposed on the drilling bit and holds constant within close limits any weight set by the driller. By simple electrical

control the automatic features may be disengaged and the hoist controlled by hand. It thus serves as a reliable, ever ready stand-by substitute for the draw works. The unit may also serve as an auxiliary hoist, useful in "rigging up" and in "making up" drill-pipe and casing joints. A crank provided on the gear-unit drive shaft serves as a means of operating a jerk line.

HYDRAULIC-FEED ROTARY DRILLING EQUIPMENT

Careful study of the foregoing sections in this chapter will, it is hoped, have impressed the reader with the importance of securing control of bit pressure in rotary drilling and will have suggested that, when mechanically controlled equipment is used, the necessary accuracy of control may be attained only through the use of special machinery of considerable complexity. Many of the difficulties that have been mentioned may be overcome and accurate control of bit pressures more readily secured through the use of hydraulically controlled rather than mechanically controlled equipment. In the hydraulic method of control, such part of the weight of the drill stem as is not needed to create the necessary bit pressure is supported on one or more pistons operating in hydraulic cylinders and the bit pressure is controlled by regulating the hydraulic pressure within the cylinders. Control mechanism of fundamentally different character is required when this system of control is used. In such a system the superstructure of the derrick carries none of the drill-pipe load while drilling is in progress.

The Diamond Drill.—The hydraulic method of control of bit pressure was first applied in connection with diamond drilling. The diamond drill has been developed primarily as a means of taking cores rather than of "making hole," and the mechanism and cutting medium used are of a nature that require accurate control of bit pressure in order to avoid breakage or loss of diamonds and improper functioning of the equipment. For many years the diamond drill was considered inappropriate for use in drilling for oil, though it had found extensive use in prospecting for the metals, for coal and other non-metallic products. Probably the chief reason for this belief was the fact that the earlier types of diamond drills were incapable of drilling holes exceeding about 2 in. in diameter—too small for efficient oil production in the event that oil was encountered. More recently the diamond drill has been further developed, and heavier models capable of drilling holes of larger diameter have been introduced and used to some extent in drilling for oil.

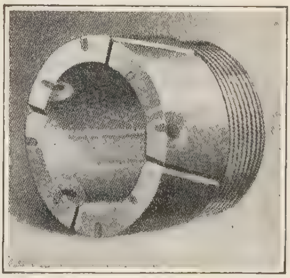
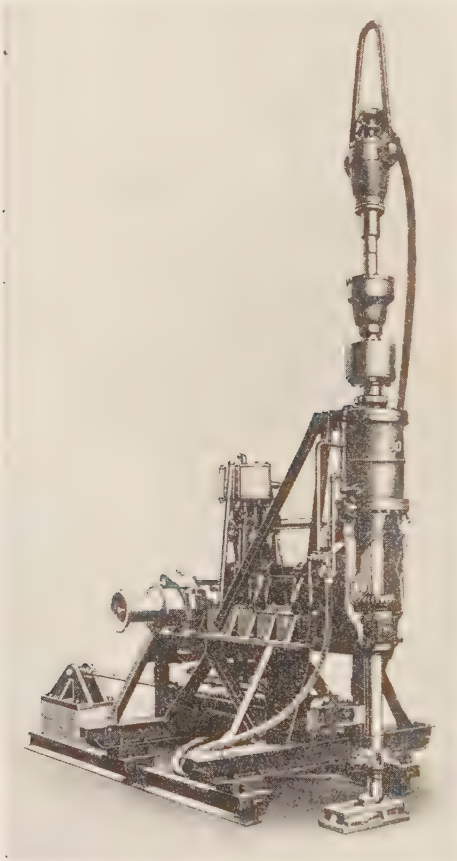


FIG. 97.—Diamond drilling bit.

The diamond drill is equipped with an annular steel bit, on the cutting edges of which are set a number of black diamonds (see Fig. 97). Owing to the high cost of "bort" diamonds, fragments of a hard, metallic alloy are sometimes substituted. The

bit is mounted on the lower end of a core barrel, which in turn is supported by a stem made up of "rods" of flush-jointed, square-threaded, special steel tubing, furnished in joints 5, 10 or 20 ft. in length and of a diameter somewhat smaller than the bit. The drill stem used has a smoother surface—since there are no collars used—and is smaller in diameter than ordinary rotary drill pipe. For the deeper drilling characteristic of oil-field operations, rods $2\frac{3}{8}$, $2\frac{7}{8}$ or $3\frac{1}{2}$ in. in outside diameter are generally used.

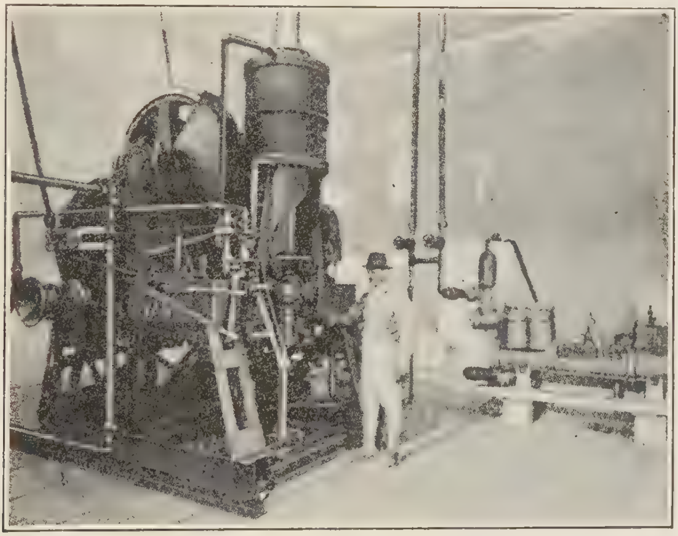


(*Courtesy of Sullivan Machinery Co.*)
Fig. 98.—Sullivan diamond drilling machine.

The surface equipment includes the drilling machine, mounted on substantial steel or timber supports at one side of the position selected for the hole, a small reciprocating water or mud pump, a steam boiler, a water-supply tank, connecting steam and water piping and miscellaneous tools. A light derrick, tripod or mast, is erected over the drilling machine to provide something to pull against in handling the column of drill rods which in a deep hole of large diameter may aggregate many thousands of pounds in weight. A sheave, over which the hoisting cable is passed, must be supported about 60 ft. above the mouth of the well, and "finger boards" for stacking 50-ft. stands of drill rod in a position slightly inclined from the vertical should also be provided. Where the overhead structure does not afford sufficient head room to

handle 50-ft. stands, shorter ones may be used; but the time required to draw out the rods and reinsert them in the well is increased. Time spent in handling rods is particularly important in diamond drilling if the usual form of bit and core barrel are used, since they must be run in and out with each 10 to 20 ft. of progress, depending upon the length of the core barrel.

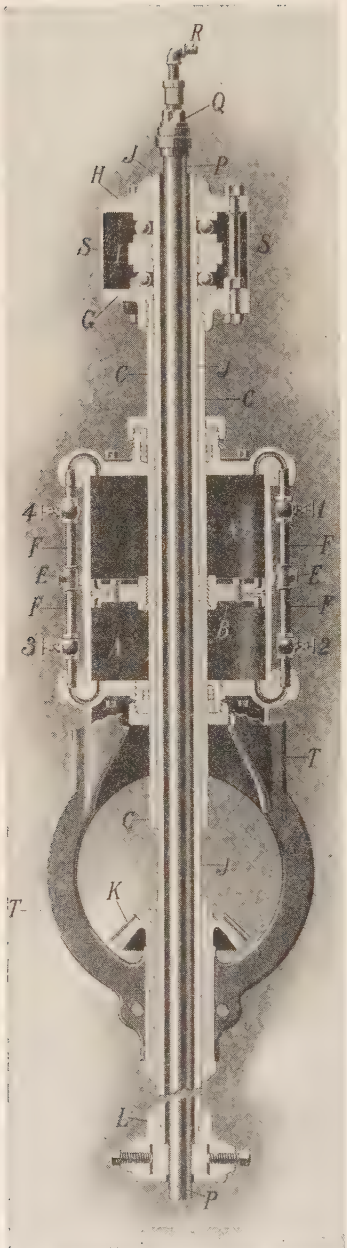
The diamond drilling machine is assembled as a unit on a structural steel or timber frame (see Fig. 98) and comprises a vertical, twin-cylinder steam engine (or a gas engine may be used) which transmits power by a drive shaft and intermediate gearing, at either of two (sometimes three) different speeds to the drive rod. The drive rod has a chuck on its lower end for gripping the drill rod and extends up through the hydraulic cylinder. Enclosed in a suitable steel housing, on the upper end of the drive rod, are the ball-bearing supports which receive the thrust due to the weight of the column of drill rods in the hole and transmit it to the piston in the hydraulic



(*Courtesy of Sullivan Machinery Co.*)

Fig. 99.—Sullivan diamond drill used in deepening 4,000-ft. well, Signal Hill field, Calif.

cylinder. The column of drill rods extends entirely through the drive rod and is equipped on its upper end with a swivel, which provides a means of forcing water or thin mud fluid down through the rotating column of drill rods. This fluid is delivered under high pressure from the circulating pump through an armored, flexible hose. A bail on the swivel affords a means of attaching the hoisting cable by means of which the column of rods may be lifted. This cable passes up over a sheave at the summit of the derrick or other superstructure provided, thence down to a power-driven hoisting drum on which the surplus cable is wound. In light machines intended for shallow drilling the hoisting drum is a part of the machine assembly and is driven usually at either of two speeds by gearing from the same engine that rotates the column of drill rods. For larger machines, such as that illustrated in Fig. 99, a more powerful, three-speed hoist is provided, mounted as a separate unit, and driven by a separate engine of sufficient capacity to handle long columns of drill rod or casing at appropriate speeds. An 11- by 11-in. twin-cylinder engine, developing about 150 hp., is used in driving the hoist accompanying the drilling machine illustrated in Fig. 99. Safety clamps support the column of drill rods in the well at such times as it is disengaged from the drive-rod chuck or is not supported from the crown sheave. The



(*Courtesy of Sullivan Machinery Co.*)

FIG. 100.—Vertical section through hydraulic cylinder and drive of diamond drill.

entire machine may be moved back on floor slides or rails so that the hydraulic cylinder will be out of the way at such times as the column of drill rods is being withdrawn from the hole and uncoupled. Catheads assist in making up rod joints and in other light duties where power is required.

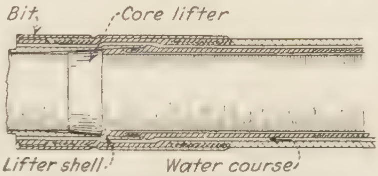
Figure 100 shows a vertical section through the hydraulic cylinder and drive rod. The column of hollow drill rods *P*, extending down to the core barrel and bit in the bottom of the hole, passes entirely through the drive rod *J* and is gripped by chuck *L*, which is screwed to the lower end of the drive rod. Power is applied to miter gear *K*, rotating the drive rod *J* to which it is splined. The drive rod rotates within the hydraulic piston rod *C* and may be raised or lowered with it, sliding through the miter gear, whose splines slide in grooves in the drive rod. The drive rod, in its upward or downward movement, carries with it the chuck and column of drill rods. Casting *T* supports the hydraulic cylinder and provides a lower bearing for the drive rod.

The hydraulic cylinder is filled with water, both above and below the piston. By admitting water under pressure to one side of the piston, through pipe *E* or *F*, and releasing an equal amount from the other side, the piston—and with it the drive rod and column of drill rods—may be moved up or down. Adjustment of valves 1, 2, 3 or 4 controlling the flow of water into and out of the hydraulic cylinder permits of accurate adjustment of the rate of descent of the column of drill rods and the pressure permitted to bear upon the bit. In effect, the hydraulic piston and cylinder are equivalent to an hydraulic jack which carries the weight of the column of drill rods and yet allows it to revolve freely—a much more sensitive and delicate control than is afforded by the draw works of the ordinary rotary rig.

Again, with reference to Fig. 100, the drive rod *J* is supported by ball bearings *I* in housing *S* on the upper end of the piston rod *C*, two sets of ball bearings being provided, one to receive upward and the other downward thrust. The drive rod is thus caused to move positively up or down with the piston rod, yet permitting the former to rotate freely within the latter. The ball bearings operate in an oil bath, and the top and bottom of the housing, *G* and *H*, must be suitably reinforced and bolted together to receive the vertical thrust. A swivel *Q* permits of making connection at

R with a source of water or mud fluid under pressure. This fluid, pumped down through the column of hollow drill rods, flows out into the hole through passages in the bit and rises to the surface between the drill rods and the walls of the well, carrying the pulverized drill cuttings to the surface and keeping the bit free of accumulated material.

The bit is of such form that it cuts a solid core out of the center of the hole, the resulting rock core being received and retained by a core barrel placed above the bit, between it and the lower end of the column of drill rods. The circulating fluid flows through a passage about the core barrel, as shown in Fig. 101. When a depth of hole slightly less than the length of the core barrel has been drilled, the bit, core barrel and rods must be hoisted to the surface and the core removed from the barrel. When a core is not desired, a fishtail, disk, cone or other form of rotary bit may be used without the core barrel. In this case, of course, the rods need not be withdrawn from the well until the bit becomes dulled.



(*Courtesy of Sullivan Machinery Co.*)

FIG. 101.—Longitudinal section through Sullivan bottom-discharge diamond drill core barrel.

In drilling, when such progress has been made that a new 10-ft. rod must be added to the drill column, this may be done by supporting the column of rods in the safety clamps, disengaging the chuck, unscrewing the joint at the lower end of the uppermost 10-ft. section, hoisting it out of the drive rod, coupling on the new rod, lowering it through the drive rod and connecting again with the column in the well. The column of drill rods is then again gripped by the chuck, the safety clamp is released and drilling resumed. In withdrawing the drill rods from the hole, they are uncoupled in stands, usually five joints or 50 ft. in length, and stood on end at one side of the rig. The column in the well must be supported on the safety clamps while each joint is broken and stacked. The hoisting drum used in manipulating the rods is operated with two or three sets of gears in suitable combinations for hoisting the full weight of the column of rods from any ordinary depth, without the necessity of using double blocks. The hoisting drum is controlled by means of a powerful, wood-lined band brake, operated by a hand lever, and is adjustable for wear.

Three pumps are used with the machine illustrated in Fig. 99: a clear-water duplex steam pump, 6 by 4 by 6 in., to operate the hydraulic feed, and two 10- by 5¾- by 12-in. mud pumps to maintain circulation. The latter are operated by a 100-hp. steam engine, identical with that which drives the draw works. These two engines are cross connected by means of a reverse clutch unit so that it is possible for the power to be applied either to pumping or hoisting as may be required in an emergency. This arrangement is particularly useful when hoisting the column of drill rods in a deep hole, as it enables the full power of the pumping engine to be applied in tandem with the hoist power unit to the work of hoisting; or, if one of the engines is shut down, emergency power for either the pumps or the hoisting drum is available from the countershaft.

Many styles and sizes of diamond drilling machines are available and have been widely used during years passed. Light diamond drilling outfits are used to some extent in coring operations in the older American fields as a means of securing information concerning sand conditions and residual oil content in introducing secondary recovery processes. The largest size of diamond drilling machine available on the market is illustrated in Fig. 99. This machine has been used in drilling 4-in. holes at depths of 4,000 to 5,000 ft. in the Long Beach field of California.

The chief field of the diamond drill in the petroleum industry will probably be found in exploration and prospecting work, where geological information is desired

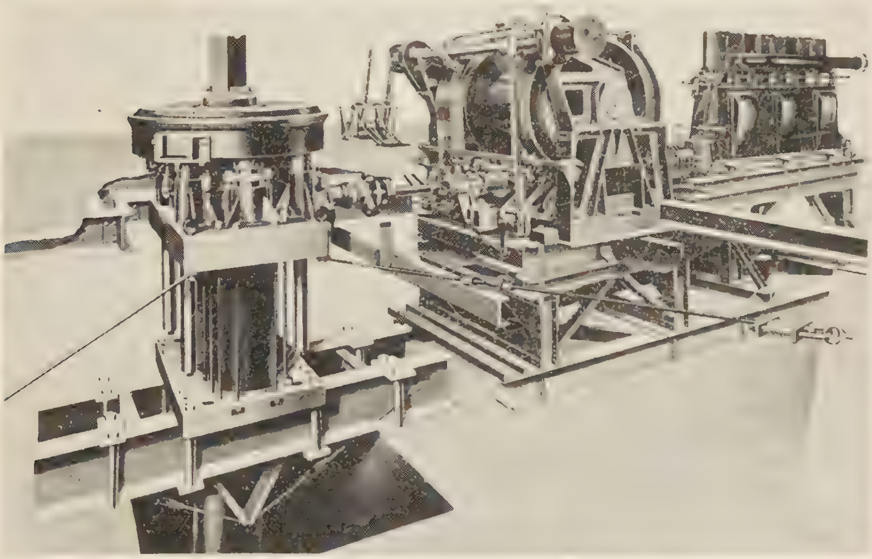
rather than a well through which oil may be efficiently produced. Because of its speed and economy, the diamond drill offers what is often the most inexpensive means of determining whether oil is or is not present under a given location. Furthermore, it provides the geologist with an actual core of the rock formations penetrated, showing the material just as it occurs in place; and by proper measurements the cores may even be oriented with respect to the compass so that the amount and direction of the dip of the strata may be approximately determined. Such information is invaluable in prospecting for oil. And when it is remembered that in this work many dry holes must be drilled for every one that results in discovery of oil, it is apparent that the loss which results through inability of the small-diameter diamond drill hole to produce oil economically is, after all, a small matter. Furthermore, the diamond drill hole may be reamed to a 50 per cent greater diameter at small cost if production is secured. The primary purpose of the wildcat well is to secure information, not to produce oil, and if this principle is recognized, the diamond drill is probably better adapted to the work than any other.

While it is generally conceded that the diamond drill is not well adapted to the drilling of oil wells in cases where a means of producing oil from a known oil deposit is the objective, there are notable exceptions which seem to indicate that under favorable conditions wells might be economically drilled for production by this method. For example, in the Panuco field of Mexico a diamond drill was used in the drilling of a well which was brought in with an initial production of 1,200 bbl. per day and subsequently successfully operated as a producing well. The well was drilled to a depth of 2,153 ft. and was finished with a minimum diameter of 3⅝ in. Gas pressures in excess of 750 lb. per square inch were encountered. The drilling speed, using the diamond bit in hard rock, averaged 75 ft. per day, but it is probable that double this footage could be maintained with a skilled crew and a longer core barrel than the 13-ft. barrel which was used. This well was completed in less than 90 days, though the average time of drilling to production in the district, with cable tools, is 5 months. The cost was about 60 per cent of the current contract price in the field. About 85 per cent of the core was extracted.

Other wells have been drilled for oil with diamond-drilling machines in the fields of Canada, Burma, California, Argentina and Venezuela, particularly in exploration work. Economy in casing is an important advantage of the diamond drill in comparison with other drilling methods, owing to the ability of the diamond drill to operate with smaller clearances. Forty per cent saving in casing requirements is claimed for the diamond drill, and, largely because of this, it is asserted that wildcat wells can be drilled for 20 per cent less than by other methods. The capacity of the larger machines also compares favorably with other types of equipment. An operator in Venezuela has set 200 ft. of 16-in. casing, 1,000 ft. 11¾-in., and 4,050 ft. 6⅝-in. in 56 days. Continuous core was recovered in this well whenever desired.

The Doheny-Stone Hydraulic Feed Rotary Equipment.—Appreciation of the advantages of hydraulic control, through experience in diamond drilling, led Mr. F. Stone to attempt its application to the ordinary form of rotary drilling equipment. With the assistance of a capable mechanical engineering organization, the result of Mr. Stone's enterprise is the modern Hydril rotary drilling outfit now marketed by the Doheny-Stone Drill Company. Accurate regulation and control of bit pressure have been the principal motive behind the design of this equipment. The designers and manufacturers have departed widely from the type of equipment that has become almost a standard in rotary drilling and have

developed a mechanism that embodies many novel features. The most important feature, however, is the substitution of hydraulic control of the descent of the drill pipe during drilling for mechanical control. In addition to this unusual feature, the Hydril equipment utilizes shaft-and-gear transmission for both the rotary table and draw works so that there are no exposed sprockets and chains. A special type of flush-jointed drill pipe is also available for use with this equipment, though the usual type with collars and tool joints may be used if desired. The rotary



(*Courtesy of Doheny-Stone Drill Co.*)

FIG. 102.—General view of several parts of the Doheny-Stone (Hydril) rig.

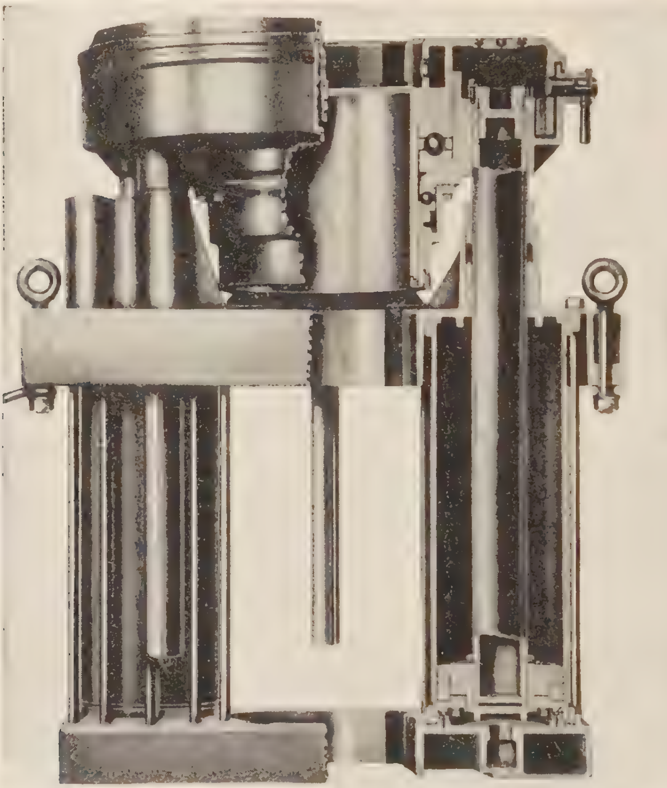
table and draw works are heavier than the usual rotary equipment, and the manufacturers have developed a special three-cylinder vertical steam engine to drive it. The general appearance of the Doheny-Stone rig as a whole differs radically from that of the usual type of rotary. Figure 102 illustrates the general design and arrangement of the three principal units.

The rotary table is supported by two massive hydraulic jacks with long pistons capable of moving up and down through a distance of 5 ft. (in one model, 10 ft.) (see Fig. 103). The principal supporting element is a large steel-base casting, which serves as a bottom cylinder head and is set upon and anchored to two heavy 20-in. I-beam structural members laid across the cellar. These I-beams are reinforced by trussing and are securely anchored into concrete foundations. Two copper-lined and wire-wound steel cylinders serve as spacers between the stationary top and bottom cylinder heads. The cylinders are held in place by a number of heavy through bolts. The whole table is steadied in a vertical position by four radial tie rods extending to the four corner piers of the derrick. Heavy springs are introduced into these rods to

insure flexibility and to absorb shocks, as well as to eliminate vibration. Upon the upper cylinder head is mounted the bevel gear box through which the table is driven.

The reciprocating and rotating part of the rotary unit is supported upon two $6\frac{7}{16}$-in. piston rods, to the lower end of which 15-in. pistons are attached. The moving part is guided, and lateral stresses are taken care of by four large-diameter guide rods attached to its base and sliding up and down with it through guide bushings in the top cylinder head.

The table is mounted upon roller bearings operating in heat-treated raceways. The hold-down ring is also incorporated within the table and is also of roller-bearing



(*Courtesy of Doheny-Stone Drill Co.*)

FIG. 103.—Doheny-Stone (Hydril) rotary table.

construction and completely protected. The table gear is an internal spur gear, integral with the table. It is driven by a spur pinion, straddle mounted within the table base upon Timken roller bearings. The gearing is completely enclosed. The pinion shaft is connected by a flexible coupling to the vertical gear-box shaft which in turn is integrally splined and slides vertically during the table movement through a driving sleeve, also Timken mounted, in the gear box. A bevel miter gear is mounted upon this sleeve and is driven by a similar gear on the drive shaft which passes out of the gear box and is connected through another flexible coupling and clutch to the transmission of the draw works.

The rotary table and the top cylinder head below the table are both fitted with bushings and slips so that it is possible to support three strings of pipe at once, one on

the inner cylinder head, one in the table slips and one on the casing hook. Bushings and slips are provided in the table for gripping either Hydril flush-jointed drill pipe, or the usual square "kelly." The largest size of Hydril table is capable of passing and rotating 28-in. fishtail or disk bits and of handling drill pipe to the greatest depths yet attained.

The hydraulic pistons are actuated by a small, separately driven pump, and the hydraulic cylinders are of sufficient size to permit of handling weights as great as 150 tons at 800 lb. pressure.

When drilling is in progress, the column of drill pipe is at all times supported by the rotary table. The hoisting cable and blocks are used only in hoisting the drill pipe out of the hole when it is necessary to change bits. The table and hydraulic cylinders may support the entire weight of the drill pipe or such part of it as may not be necessary to maintain proper pressure on the bit. The drill stem is positively gripped with slips in the table so that it cannot move up or down relatively to the table. Hydraulic pressure within the hydraulic cylinders is controlled by valves on the pressure line from the pump, and on the discharge lines. These valves are conveniently located to the driller in his control position, and pressure gages are connected in the water manifold to register the pressure applied. Just enough pressure is carried in the hydraulic cylinders to permit the table and drill stem to descend at any desired rate. A very sensitive control is afforded, it being possible to adjust for a feed of as little as 42 in. in 10 hr. or as much as 42 in. in ½ min., as well as all intermediate rates.

To enable the driller to have definite knowledge of the exact weight resting on the bit, a differential gage is provided which indicates at all times the active unsupported weight of the drill pipe without the necessity of making any calculations. With such flexibility and knowledge of exact pressures applied—combined with simplicity of adjustment and accurate regulation of these pressures—a driller can control the bit almost as if it were on the surface. He can regulate it to suit the drilling conditions with a nicety not possible with any other means of control, cutting rapidly or slowly as his judgment indicates to be best procedure for the formations encountered.

The Hydril draw works is integrally mounted upon a solid and rigid cast-steel base, with all bearings secured in accurate alignment. The unit rests on a separate concrete base or special steel foundation, tied into the foundations of the derrick. As a result of this substantial foundation, there is less vibration noticeable in the derrick. The main drive is entirely geared. There are no open chains in any part of the equipment, and but one chain, completely enclosed, is used in the entire unit. This drives the cathead shaft and is in operation only during such times as the cathead is in use. The shaft drive from the engine comes into a three-speed transmission gear box, completely enclosed. The drive is taken from the gear box to the drum shaft through a herringbone gear and pinion, controlled by a positive jaw clutch, constituting the high-speed drive of the drum shaft. A low-speed drive is provided for the drum through a planetary gearing at the opposite end so that with the two-speed drum drive and three-speed transmission, six speeds, covering a wide range, are available for hoisting. The hoisting drum is 24 in. in diameter, and brake drums are 46 in. in diameter with 10-in. faces. A brake-band truss surrounds the contact surface of the band, providing for accurate adjustment of the friction surface to the drum and for rigid and positive braking action. The drum and drum shaft are mounted on large-diameter Timken bearings and the brake drums are of pressed forged steel.

The Hydril three-cylinder vertical engine is also a novelty among oil-field engines. The three cylinders are each 10 by 10 in., and it is a double-acting, piston-valve-controlled engine, with triple-throw crank shaft, developing 320 hp. at 320 r.p.m. on 150-lb. steam pressure. The engine is entirely enclosed in a metal casing and mounted on two heavy steel skids.

The Hydril flush-jointed drill pipe, illustrated in Fig. 104, is a development of the flush-jointed "rods" used in the diamond drill. As illustrated, the joints are internally threaded at each end and are jointed by an externally screwed coupling. A special form of square thread on a conical surface is used for convenience in quickly making up and disconnecting the drill pipe. Two threads are used, in step form, engaging as one. The external surface is a smooth cylinder with no projections to hang up on obstructions or gouge out the soft places along the walls of the well.

(*Courtesy of Doheny-Stone Drill Co.*)

FIG. 104.—Hydril step-jointed coupling drill pipe.

At left: external flush-jointed drill pipe; at right: internal flush-jointed drill pipe.

For use with the Hydril equipment, the manufacturers have also perfected various other tools, some of them of novel design, including special drilling bits, reamers, and coring and fishing tools.

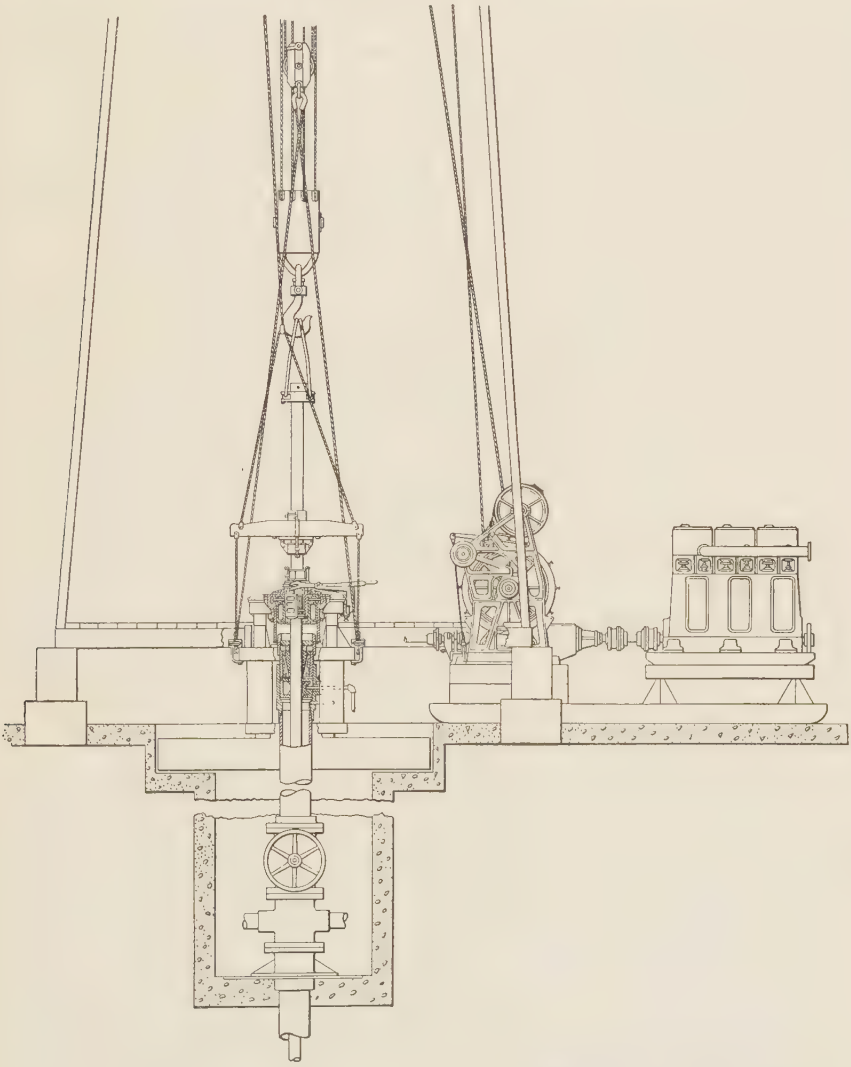
Some remarkable records are being made with Hydril equipment. In one case, in the Oklahoma City field of Oklahoma, a well was drilled to a depth of 6,400 ft. in 92 days, whereas the average drilling time for a well in this field to comparable depths with ordinary rotary equipment is 135 days. The average well in the Oklahoma City field requires 66 sets of cone cutters in drilling to 5,200 ft., while the well drilled with Hydril equipment required only 40 sets. The Doheny-Stone equipment has also achieved some unusual records in the deeper fields of California, notably in the Kettleman Hills and Ventura fields, where it has been in competition with standard types of equipment.

The Hydril equipment is well adapted to drilling in very high pressure formations or to dealing with heaving sands and shales characteristic of high-pressure formations. By closing in the space about the drill pipe with a suitable packing head or blow-out preventer and releasing the drilling fluid through a valve under back pressure, it is possible to add many hundreds of pounds of pump pressure to the static pressure afforded by the drilling fluid. Special pull-down equipment is used in the derrick to force the first few stands of drill pipe into the well against the pressure and also to snub them out when withdrawing the drill pipe (see Fig. 105).

The Sheldon-Burden Hydraulic Feed Rotary Equipment.—Another style of hydraulic control rotary equipment that is finding use in oil-well drilling is manufactured by the Sheldon Machinery Corporation. The Sheldon-Burden rotary table differs from the Hydril equipment described above chiefly in that the table is carried on a single hydraulic cylinder concentric with the drill stem, instead of two separate cylinders. It is designed for use with any of the regular types of rotary rigs, affording many of the advantages of the hydraulic feed principle, while still using the standard rotary equipment. The table may be used either with or without the hydraulic control. By disconnecting four bolts the table sleeve and hydraulic feed mechanism

can be lifted out of the table, and the table may then be used as in ordinary rotary practice.

Another model of the Sheldon-Burden line mounts both the draw works and the hydraulically controlled table on a single steel base, and both the table and the draw



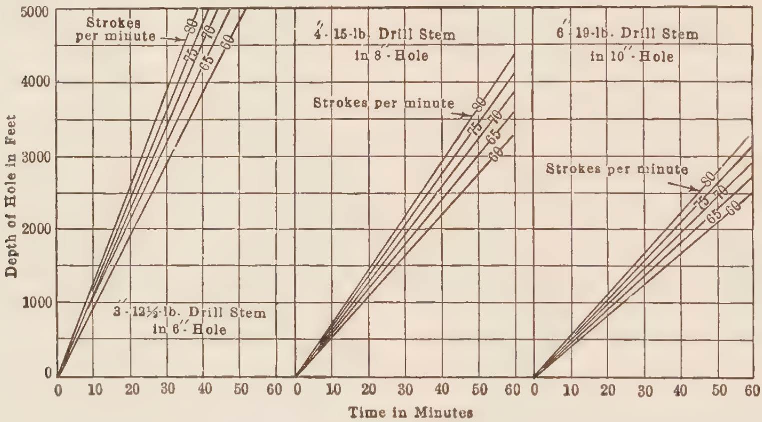
(*Courtesy of Doheny-Stone Drill Co.*)

FIG. 105.—Hydril rotary machine, draw works and steam engine, showing pressure drilling equipment.

works are gear driven. A wide range of table and hoisting speeds is afforded. A speed-reduction gear provided with the machine makes it adaptable to any type of power. Sheldon-Burden equipment has been used advantageously in drilling through unusually high-pressure formations in Canada and Mesopotamia.

IDENTIFYING FORMATIONS AND GATHERING LOG DATA WITH THE ROTARY EQUIPMENT

The rotary driller recognizes changes in formation by the action of the drill stem, the rotary table and the circulating pump. On withdrawing the drill stem from the hole, evidence concerning the nature of the material penetrated is also to be gained from the condition of the drilling bit. An examination of the drill cuttings brought to the surface by the circulating fluid and deposited in the mud ditch will indicate more definitely the lithological characteristics of the material in the bottom. Table XXIV gives the mechanical reactions and physical appearance of the circulating fluid for each type of rock ordinarily encountered in sedimentary formations.*



(*After J. R. Suman and R. E. Collom.*)

FIG. 106.—Time required for cuttings to reach surface when using a 5¾- by 12-in. duplex pump, operating under 60 per cent efficiency.

Progress in depth is estimated by the movement of the drill stem through the rotary table. The length of rotary drill pipe below the rotary table is definitely known at all times by steel-tape measurement, and the grief stem is usually marked at 12-in. intervals as a further aid for the driller in determining the depth at which each change in character of the formation is encountered.

In order to correlate the samples obtained from the circulating fluid with the mechanical reactions of the drill, it is necessary to determine approximately the time necessary for the circulating fluid to transport material from the bottom of the hole to the surface. This is a function of the speed and delivery capacity of the mud pump, the depth and diameter of the holes and the diameter of the drill stem. The delivery time may be computed with fair accuracy if these variables are known

* COLLOM, R. E., Prospecting and Testing for Oil and Gas, U. S. Bur. Mines, *Bull.* 201, p. 101, 1922.

Table XXIV.—Mechanical Reactions and Physical Appearance of the Circulating Fluid for Various Sedimentary Rocks in the Process of Rotary Drilling*

Field and formation	Action of pump and tools	Cuttings	Effect on bit
Midway Field, California:			
Hard sand...	Pump runs with low pressure, sand takes some fluid; tools jump.	Sand shows in ditch with thin mud.	Bit badly worn with only 1½ hr. drilling in hard sand.
Loose sand...	Pump runs with low pressure; frequently takes mud; necessary to thicken fluid; when bit is stopped and set on bottom, sand can be sluiced out with mud stream, causing tools to plunge.	Sand shows in ditch with thin mud.	Does not cut bit appreciably.
Sandy shale..	Pump runs with low pressure; digs like sand, but with bit set on bottom cannot sluice out any hole below it.	Fragments in ditch with thin mud; streaked samples on tools.	Cuts bits considerably.
Soft shale....	Pump runs with medium pressure.	Small fragments in ditch; soft chunks on bit, with streaks upon breaking.	Cuts bit very little.
Hard shale...	Pump runs with more pressure than in sand; tools jump.	Shows in ditch in small flakes and chunks; very little sticks to bit.	Cuts bit badly.
Clay........	High pressure on pump; run thin fluid; pump sometimes stalled; machinery runs smoothly with tension on table and chains; necessary to spud tools in order to clean the bit.	Change of color is the only showing of clay formation in the ditch; plenty of clay sticks to the bit.	Does not cut bit.
Shell........	Pump runs freely; tools, chains and tables jump.	Small fragments show in thin mud in ditch.	Cuts bit badly.
Sea shells....	Pumps run freely, unless in clay.	Fragments and some perfect specimens show in ditch.	Do not cut bit.
Northern Louisiana fields			
Hard rock...	Pump runs slowly with low pressure.	Cuttings show in ditch in thin mud.	Wears bit badly and to all shapes.
Hard shell. Hard limestone.... Sand (hard and soft).	Run without much steam pressure; cuttings easy to handle.	Cuttings show in thin mud in ditch.	Wears bit badly and to all shapes.
Shale........	Run with nearly full head of steam; pumps handle cuttings without spudding but have to work hard.	Fragments show in ditch.	Does not wear bit appreciably.
Gumbo......	Run pump with full head of steam; even then continual spudding needed to mix cuttings enough to allow free returns.	Will ball up and shut down pump; no show except color in ditch.	Does not wear bit appreciably.
Chalk.......	Run pumps with full head of steam; does not ball up; sometimes have to spud.	Small fragments of hard chalk in thin mud.	Does not wear bit badly; hard streaks wear bit.
Gypsum.....	Does not take much steam pressure; pump can be run slowly; gypsum balls up on point of bit and retards progress, but has no effect on pump.	Shows in flakes or small particles in thin mud; balls up on bit.	Does not wear bit appreciably.
Salt.........	Drills slowly; returns not hard to handle; no effect on pump.	Small particles occasionally	Does not wear bit appreciably.
Southern Oklahoma:			
Shale, various colors.	Tools run smoothly, medium pump pressure; drills fast.	Fragments show in thin mud.	Does not wear bit appreciably.
Sandy shale..	Tools run smoothly, chain "settles down;" drills fast.	Fragments show in mud like shale.	Wears bit more than shales.
Gumbo......	Tools run in jerks; high pump pressure; hard to drill; driller has to reverse engine and spud tools to clean bit.	No show in ditch other than color; sticks to tools.	Does not cut bit.
Clay........	Tools run smoothly; easy drilling; high pump pressure.	Balls up on bit; no sample in ditch other than color.	Does not wear bit appreciably.
Limestones....	Tools jump and jerk when cutting; low steam pressure; hard to drill.	Fragments in ditch occasionally.	Wears bit and reduces its gage.

* After R. E. Collom, U. S. Bur. Mines, *Bull.* 201.

and can be readily checked by placing a quart or two of red paint or some distinctively colored dye in the pump suction and noting the time necessary for it to travel through the drill stem and back to the surface. The time necessary to reach bottom—which must of course be deducted from the round-trip time to determine the delivery time from the bottom to the surface—can be definitely determined if the delivery capacity of the pump and the length and internal diameter of the drill stem are known. Actual delivery times vary from a few minutes to as much as 2 or 3 hr. (see Fig. 106).

The mud ditch through which the well fluid flows from the well to the sump in which the surplus is stored is usually equipped near its upper end with riffles or depressions which serve to settle out and impound the coarser material. Samples useful in identifying formations may readily be secured by shoveling some of this coarse material from the ditch and washing thoroughly with clear water to remove the mud. If an uncontaminated sample from the stratum in which the bit is working is desired, drilling is stopped, but circulation is continued until no more cuttings are brought to the surface. The mud ditch is then shoveled out and drilling is resumed. At the expiration of the calculated time necessary for cuttings to reach the surface they are looked for in the mud ditch. Some drillers use a large-size thread protector (from the open end of a joint of casing) in the trench as a means of impounding a sample. Color plays an important part in the identification of materials in the mud ditch. Clays and shales will usually be so finely pulverized by the drill that the color imparted to the circulating fluid by them is the only means of identifying one stratum from another.

In some kinds of material, particularly clays and shales, drilling for a few minutes without circulation of fluid will ball up a mass of pulverized cuttings on the bit which is brought to the surface when the drill stem is drawn out.

Because of the rapid progress made in soft formations and the difficulty of recognizing slight changes in the nature of strata penetrated, the rotary method does not yield so reliable and complete a log as the churn drilling method. A body of rapidly alternating layers of shale, sand and clay, for example, will usually be logged as a single stratum of sandy shale, that is, the rotary drill logs show fewer formation changes and seemingly thicker beds. Mechanical difficulties in operation of the drill will often be interpreted as due to hard rock. The "bowlders" commonly found in rotary logs, for example, are in most cases inferred from the action of the drill on hard strata and on bodies of shale.

ROTARY CORE-DRILLING AND SAMPLING DEVICES

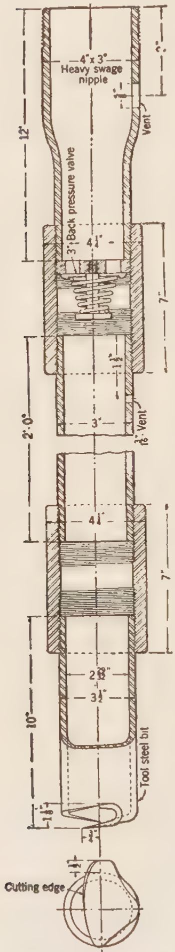
One of the principal objections offered to the use of the hydraulic rotary system of drilling during the earlier years of its development was

that it provided no adequate samples of the formations penetrated. Logs of wells assembled on the basis of mechanical reactions of the equipment and inspection of finely pulverized returns brought to the surface by the circulating fluid were found to be undependable. Owing to the hydrostatic pressure developed by the long column of heavy mud fluid, oil- and gas-bearing sands were drilled through and sealed off without their presence being made known. These objections to the use of the rotary equipment have now been largely removed by the development of dependable rotary coring devices.

Early efforts in this direction were only partially successful in that the devices used were unreliable and the cores secured were often imperfect. One of the first and simplest coring devices, more properly called a "sampling device," consisted of a piece of casing about 3 ft. long and 3 to 8 in. in diameter, on the bottom edge of which V-shaped notches or teeth were cut either by machine methods or with the aid of the oxyacetylene torch. The teeth thus formed were usually "set" alternately to one side and the other, like the teeth of a saw, to maintain clearance on both the inside and outside. Attached to the lower end of the drill stem, this device is rotated into the formation under moderate pressure. As the core barrel is revolved and the teeth cut into the formation in the bottom of the well, the loosened material is forced upward into the barrel and there retained by frictional contact. A hole bored through the side of the tube near the top permits escape of the imprisoned mud fluid. Toward the end of the coring operation with this type of sampling device, the bit pressure and the rate of rotation are increased, with the purpose of "burning the core into the barrel," collapsing and overheating the teeth of the barrel until they close in on the lower part of the core. The heat developed is in many cases sufficient to actually fuse some of the constituents of the core. An alternative plan consists in raising the drill stem a foot or two and dropping it on bottom, with the purpose of bending the teeth inward to prevent the core from falling out of the barrel as the tool is withdrawn to the surface. Soft material is usually sufficiently compressed to be retained without difficulty, but hard rocks are likely to be loose in the barrel. When taking cores in hard formations, some drillers have followed the practice of dropping small pieces of cast iron into the drill stem. These metal fragments settle on top of the core in the barrel, and, on raising and lowering the barrel a few times on the core, they become lodged between the core and the barrel so that the material is effectively retained.

Another early type of core-sampling device, also in the form of a short section of pipe, supported on the lower end of the drill pipe, was simply dropped or spudded into the formation with the purpose of punching out a sample. Another style of early core barrel was of the auger type, a tube with a pointed cutting lip being mounted on the lower end of the

drill pipe (see Fig. 107) and slowly rotated into the formation. It excavates soft material in much the same manner as an ordinary post-hole auger. In drawing out the tools, the lip prevents the sample from falling out of the barrel. Holes must be provided in the swaged nipple and in the drill stem above the back-pressure valve to allow the circulating fluid to escape from the barrel.



(After J. R. Suman and R. E. Collom.)

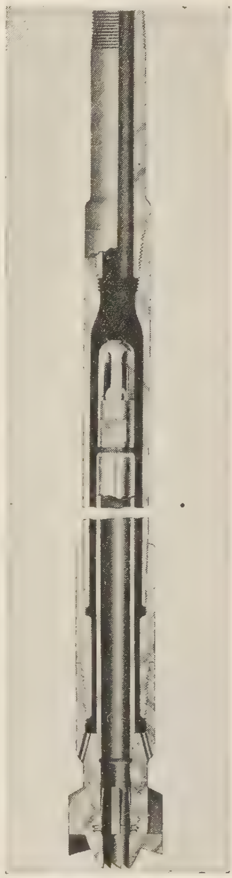
Fig. 107.—Sampling device used by Gulf Production Co.

These early types of rotary core drills, while simple in construction and low in cost, had many disadvantages. They were capable of securing only short, broken, distorted and otherwise imperfect cores, usually contaminated with mud, the material being often altered by overheating. On being withdrawn to the surface, the cores were difficult to extract from the core barrel without breaking. The hole formed had usually to be reamed out to gage, and fishing jobs were common, owing to breakage of the tool or to its becoming fast in the hole.

Difficulties experienced with these primitive coring tools eventually led to the introduction of the double-barrel core drill now used almost exclusively. Later development has resulted in the perfection of this type of core drill until, by its use, it is now possible to take long and fairly continuous cores in rocks of almost any character. The different core drills of this type may be roughly classified into two groups, one using a scraping type of bit appropriate for use in comparatively soft formations, while the other, utilizing roller cutters, is designed for hard-rock drilling.

For soft and moderately hard formations, a core drill of the type illustrated in Fig. 108 may be used. This consists of two concentric tubes with an annular passage between for mud-laden fluid, the fluid being discharged through holes just above the cutter head. The outer tube consists of several parts coupled together with screw connections. The upper connection provides a means of attaching the tool to the drill stem or drill collar. Below this, the outer barrel of seamless-steel drill pipe, 10½ ft. long, supports the lower sub and the latter is screwed to the cutter body. The replaceable cutter head is screwed on the lower end of the cutter body, and in an internal groove between the two the core catcher is supported. The inner tube is screwed at its lower end into an interior recess in the top of the cutter body. A valve of the

ball-and-disk-seat type, with a cage or "crown" to hold the ball in position over the seat, is mounted on the upper end of the inner barrel. The cutter head, the sub and cutter body are made of chrome-nickel steel, especially heat treated to secure proper hardness and wearing qualities. The cutter head is faced with a hard-facing fusion metal, such as stellite, and where extreme hardness is required, as in the taking of long cores in hard formations, fragments of tungsten carbide are embedded in the hard-facing metal. Cutter heads protected in this way yield about four times the footage secured from ordinary hard-faced heads.



(*Courtesy of Elliott Core Barrel Co.*)

Fig. 108.—Elliott rotary core drill.

In operation, the tool is lowered to bottom, attached to the lower end of the drill stem, either with or without a drill collar, and mud fluid circulated until the density of the fluid throughout the well has been equalized and accumulated drill cuttings have been removed. As light a fluid should be used as conditions in the well permit. The tool is then rotated on bottom at the rate of 30 to 40 r.p.m. with moderate bit pressure. A 10-ft. core is usually cut at one operation, and under very favorable conditions, with a 21-ft. barrel, cores as long as 20 ft. may be secured. Cores taken with this type of barrel range from 1¼ to 4 in. in diameter, depending upon the size of the hole and that of the drill pipe on which the tool is designed to operate. As the core is cut, it is forced upward past the core catcher into the inner barrel. Mud fluid imprisoned in the inner barrel above the core is forced out through the valve at its upper end into the circulating fluid channel between the inner and outer barrels. A sheath of clay, which forms around the core, serves to protect it against frictional contact with the inner barrel. When coring is completed, the speed of the mud pumps is reduced and the rate of rotation of the stem is increased to facilitate breaking off of the core. As the tool is lifted off bottom, the core catcher grips the core in the barrel and prevents it from falling out. After reaching the surface, the joint between the cutter body and lower sub is broken and the inner barrel unscrewed from the cutter body. The valve at the upper end of the inner barrel is removed, and the core forced out of the barrel with the aid of a specially designed "core puncher." The tool drills the hole to full gage so that it is unnecessary to ream after coring.

Under the conditions presented in the California fields, where the rocks to be penetrated are comparatively soft, an average of about 70 per cent of the formation cored is secured with this type of barrel. A new core head costs about $40 and the cost per foot of core recovered averages about $4. One operator in the Long Beach field of California cored

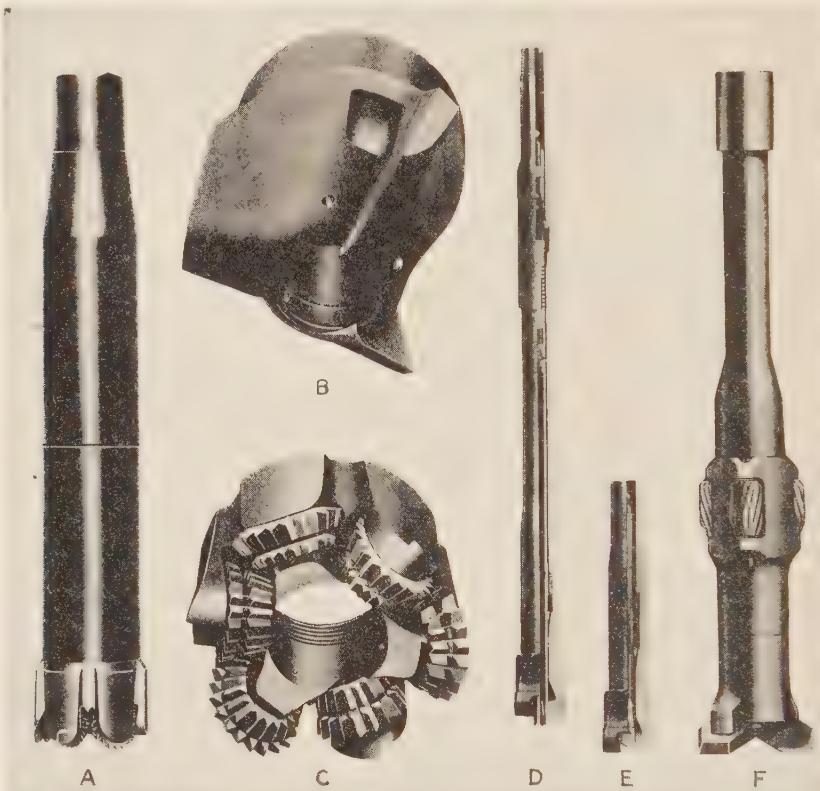


Fig. 109.—Types of core drills.

A, Hughes core bit equipped with hard-formation cutter head; *B*, Hughes core bit, soft-formation cutter head; *C*, Hughes core bit, hard-formation cutter head; *D*, Barrett-Robishaw drilling-coring bit with core-barrel assembly and *E*, with bit plug in place for drilling; *F*, Reed wire-line drilling-coring bit (see page 211).

continuously from 5,000 to 7,000 ft., averaging about 133 ft. per day. Twenty-seven tungstite-protected cutter heads were used, or an average of 74 ft. of coring per head. In the Gulf Coast region of the United States the cost of 10-ft. cores is reported to range from $42 for depths of less than 2,000 ft. up to $140 at a depth of 8,000 ft.

The roller type of core drill, used in coring hard and moderately hard formations, is illustrated in Fig. 109. The assembly of the outer barrel is very similar to that of the coring tool described in the preceding paragraphs. The inner barrel is in this case equipped with a "time-limit valve," which is adjusted to remain open for a predetermined time

against the pump pressure, permitting circulating fluid at first to flow through the inner barrel, flushing out any drill cuttings that may enter the barrel during its descent. A stiff grease, which gradually yields to the pump pressure, eventually permits the valve on the upper end of the inner barrel to close, the time of closing being indicated by change in speed of operation of the circulating pumps. The cutter head in this type of core drill, furnished as a unit, ready to screw on the body of the tool, is equipped with six pairs of conical cutting rollers which revolve on hardened ground pins, welded to the forged and heat-treated cutter head. The conical roller cutters are so spaced that the bit head rotates true with the center of the core; hence there is no eccentric motion tending to break up the core. Mud fluid is discharged under pressure from the space between the inner and outer barrels through six holes, one above each pair of cutters. The cutters are patterned after and operate in much the same way as the cutters on Hughes cone bits, described on page 210. Core bits of this type are operated at the same rotational speed and with the same bit pressure recommended for use with Hughes cone bits. The core catcher is so designed that it does not grip the core until the tool is lifted off bottom. Ten-foot cores of granite have been taken with this tool, cutting at the rate of 2 ft. per hour. Complete cores (that is, little or no loss) have also been taken through beds of hard sandstone, sandy lime and anhydrite, these being the harder types of rocks encountered in oil-field drilling. Sizes in this type of core barrel range from 1¼ to 7 in.

A recently perfected coring device is designed to permit of taking and retrieving cores without removing the drill pipe from the well. The bit used is shaped like a fishtail bit, but is axially bored to receive a core barrel which may be inserted and withdrawn through the drill pipe. Drilling is conducted in the usual manner, and when a core is desired the grief stem is detached and the core barrel dropped into the drill pipe. On reaching bottom, it is gripped in position in the bit by a special locking device. After the coring operation is completed, a small overshot, lowered through the drill pipe on a light steel cable, retrieves the core barrel and core. It is claimed that this device is capable of taking a core at a depth of 5,000 ft. in about 1 hr., the cost being less than half that with ordinary coring devices which require two trips in and out of the hole with the drill pipe of each core taken (see Fig. 109 *D–E*).

Difficulty sometimes encountered in taking cores with the rotary equipment may be due to a crooked stem, causing the tool to operate eccentrically, or to improper consistency or insufficient volume of the circulating fluid, so that cuttings are not carried away rapidly enough and become embedded in the core. Pieces of iron or steel in the bottom of the hole, the result of earlier breakage of tools or well equipment, will usually cause trouble if present. Hard "shells" may cause rapid dulling

of cutter heads. Excessive bit pressure or too rapid rotation may result in breakage and "burning" of the core or damage to the cutter head.

TABLE XXV.—1920 ROTARY DRILLING COSTS, ELK HILLS FIELD OF CALIFORNIA, DEPTH 2,910 FT.

		Total cost	Cost per ft.
Derrick and rig	....	$ 5,768	$ 1.98
Casing:			
2,760 ft.; 11 in. @ $3.68 per ft	$10,156		
2,700 ft., 8¼ in. @ $2.19 per ft	5,913		
210 ft., 8¼ in. @ $2.29 per ft	1,936		
Two guides	65		
Total casing	....	$18,070	$ 6.21
Cement, 200 sacks	....	276	.09
Tubing, 2,910 ft. @ $.44	....	1,280	.44
Pumping equipment	....	170	.06
Tanks, flume, etc	....	527	.18
Total cost well equipment	....	$20,323	
Boilers (3)	....	$ 839	.29
Casing line, 1,200 ft	....	250	.09
5,000 ft. O. P. Rough (lumber)	....	275	.10
Rotary and engine repair parts	....	800	.27
Prorated charges on movable equipment	....	$ 2,164	
Oil and distillate	....	$ 170	
Packing	....	180	.53
Miscellaneous materials	....	1,200	
Materials and supplies	....	$ 1,550	
Storehouse expense (8 per cent of store's cost)	....	$ 1,925	.66
Hauling	....	2,000	.69
Light and water	....	800	.27
Tool rental	....	1,450	.50
Cementing (Perkins)	....	250	.09
Distributed expense	....	6,425	
Labor:			
Rotary crew, 100 days @ $118.50	....	$11,850	4.07
Setting boilers	....	500	.17
Setting flow tanks and flumes	....	100	.03
Miscellaneous labor, bit dressing, etc	....	1,250	.43
Superintendence	....	1,850	.64
Total, labor and superintendence	....	$15,550	
Total cost	....	$51,780	$17.79

THE COST OF ROTARY DRILLING

The cost of rotary drilling varies widely, depending upon the depth and nature of the formations to be penetrated, the method of drilling

used, the skill of the drillers employed, the diameter of the hole and the casing requirements. Costs are also largely influenced by fortuitous circumstances. The accidental loss or breakage of a tool in the well or

TABLE XXVI.—COST OF DRILLING WITH ROTARY RIG IN MIDWAY FIELD (3,277-FT. WELL, 10-IN. CASING), 1913

	Total cost	Cost per ft.
Derrick and rig:		
Lumber (106-ft. derrick)	$1,067.76	
Nails	28.04	
Bolts	24.80	
Corrugated galvanized iron	124.37	
Miscellaneous	2.10	
Rig irons	580.14	
Overhead expense on material	73.90	
Labor	283.06	
Shop work	145.03	
Teaming	453.98	
Total, derrick and rig		$ 2,783.18
Engines and boilers:		
Engine	$ 290.07	
Boilers (3)	1,305.00	
Foundations and settings	54.90	
Pipe and fittings	425.48	
Labor, erecting	150.00	
Belts	96.66	
Tanks and flume	196.46	
Lumber, foundation and flume framing	16.22	
Sump hole	100.00	
Total, engines and boilers		2,634.79
Drilling:		
Labor (drillers, toolies, circulator men)	$7,002.51	
Labor, extra (rigging up and pulling casing)	487.03	7,489.54
Drill tools	$ 523.96	
Drill stems and joints	3,760.00	
Depreciation on tools, machinery, stem bits, etc	2,909.08	
Cordage	659.84	
Casing, 10 in. (2,850 ft.)	5,007.86	
Casing, 6⅝ in. (3,277 ft.)	2,442.31	
Fuel (gas)	106.00	
Water	730.09	
Electricity	58.74	
Repairs (engine, rig and boilers)	476.58	
Oil, waste and packing	100.30	
Sundries: overhead material and superintendence, shop work, tools and machinery, ice, hose, miscellaneous	2,652.63	
Teaming	1,846.54	
Total, drilling		21,273.93
Fishing:		
Rental and loss of tools	$ 14.25	
Labor in fishing	245.00	
Total, fishing		259.25
Cementing (including finishing: well flowed):		
Tubing, 3,000 ft., 2½ in	$ 729.00	
Sucker rods (3,000 ft.), pump, etc	266.70	
Total, cementing		995.70
Grand total		$35,436.39
Total cost per foot	....	$10.86
Casing cost per foot	....	2.28
Total labor cost per foot	....	2.48
Drilling labor cost per foot	....	2.14
Working time	....	125 days
Rate per day	....	26.2 ft.

collapse of the casing, a blow-out of high-pressure gas resulting in loss of control or an unsuccessful water shut-off may result in greatly increased unit costs. Cost data therefore are of little value for comparative purposes unless the complete drilling history of the well and a thorough

description of the formations penetrated are made available. Published data on drilling costs seldom do this; indeed, few operators take the trouble to record such information.

The costs of labor, lumber, steel and other materials, of transportation, water and power supply are also important variables. Aside from regional variation, the unsettled commodity markets and readjustments in wage scales have had an important influence on drilling costs within recent years. The cost of drilling in 1920 was approximately twice that of 1913 in most American fields as a result of such changes.

The figures given in Tables XXV, XXVI and XXVII, on the cost of rotary drilling must be regarded as representing merely the cost of particular wells under the conditions pertaining, and they should not be applied except in a very general way in estimating costs for other wells drilled, perhaps under quite dissimilar conditions. It will be noted that casing is generally the greatest single item of expense in the cost of a well, while the labor cost and the cost of the rig and derrick are the only other items of comparable magnitude.

TABLE XXVII.—COST OF ROTARY DRILLING IN VARIOUS AMERICAN OIL FIELDS IN 1928*

Field and district	Depth, ft.	Cost of						Cost per foot of depth
		Derrick or rig rental	Casing and fittings cementing	Drilling	Labor, teaming and freight	Miscellaneous	Total	
Earlsboro pool, Seminole, Okla.	4,350	$ 5,000	$14,500	$37,950	$2,500	$ 750	$ 60,700	$13.95
Carr City pool, Seminole, Okla.	4,817	10,040	12,097	37,722	2,257	201	62,317	12.94
South Little River, Seminole, Okla.	4,198	6,881	12,693	35,193	2,047	15	56,829	13.54
Searight, pool, Seminole, Okla.	4,355	7,944	17,689	41,011	2,565	829	70,038	16.08
Bowlegs pool, Seminole, Okla.	4,323	7,374	11,804	48,550	3,022	1,418	72,168	16.69
Seminole pool, Seminole, Okla.	4,115	8,348	15,926	33,804	2,494	2,232	62,804	15.26
St. Louis pool, Okla.	4,199	8,998	6,886	37,248	1,982	94	55,208	13.15
Sugarland field, Tex. (Gulf)	3,400	3,754†	17,570	6,934	1,243	3,002	32,503	9.56
Racoon Bend, Tex. (Gulf)	3,500	3,293†	16,354	9,114	1,925	5,519	36,205	10.35
Inglewood, Calif.	2,300	7,380	17,760	9,300	......	13,171	47,611	20.70
Buena Vista Hills, Calif.	3,000	7,500	22,729	10,920	......	12,945	54,094	18.03
Rincon field, Calif.	3,500	9,000	32,100	19,500	......	16,160	76,760	21.93
Huntington Beach, Calif.	4,300	7,840	33,924	20,600	......	23,773	86,137	20.03
Santa Fe Springs, Calif.	5,800	6,350	45,000	33,600	......	35,974	120,924	20.85
Kettleman Hills, Calif.	7,200	7,150	64,275	51,084	......	75,228	197,737	27.46

* Compiled from data given in "Petroleum Facts and Figures," 2d ed., American Petroleum Institute.

† Charge for rig rental. Drilling rig is removed on completion of well and production rig substituted.

A convenient method for roughly estimating drilling costs involves the use of per diem rates for operating expense and average rates for drilling speed, cost of derrick, equipment and casing. Thus, for the

TABLE XXVIII.—COMPARATIVE UNIT ROTARY DRILLING COSTS, 1917 TO 1919, CALIFORNIA FIELDS

Average costs for a large company operating in the San Joaquin Valley fields of California

District	Year	Total footage	Cost per foot	Cost of operating one string of tools for 1 month
Coalinga	1917	70,800	$16.00	$ 8,600
Coalinga	1918	80,400	21.20	11,100
Coalinga	1919	44,900	24.68	10,275
Sunset	1917	165,500	12.55	9,860
Sunset	1918	143,000	14.29	9,820
Sunset	1919	84,300	17.42	9,120

conditions presented in the Los Angeles Basin fields of California during recent years the cost of a rotary rig ranged from $7,000 to $9,000 depending upon the depth to be attained. Casing costs averaged about $7 per foot of depth. The daily cost of operating a rotary rig, using three crews, each working 8 hr., averaged about $500, distributed as follows:

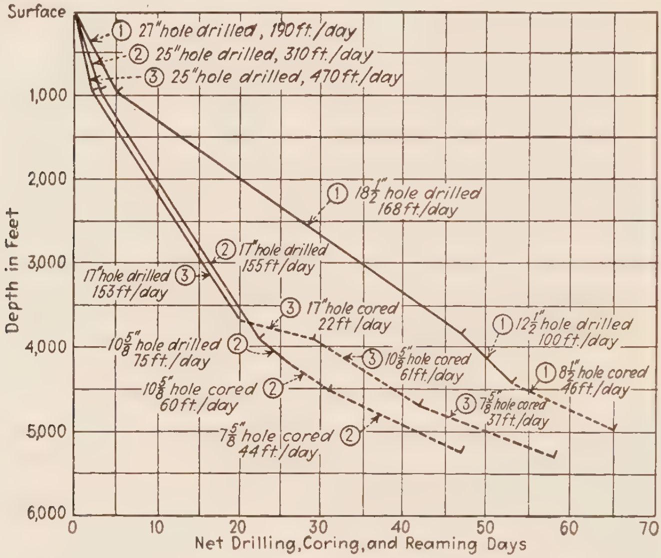
	Cost per Day
Labor	$120
Supervision	30
Fuel and water	40
Depreciation of drilling equipment	200
Tool repairs, including drilling bits	110
Total	$500

The number of days necessary to drill a well in a given locality will depend upon local conditions but may usually be estimated with approximate accuracy. Figure 110 indicates average drilling times to various depths in two California fields.

Many operators find it profitable to have their wells drilled under contract, the contractor furnishing everything necessary except the rig and derrick, water, power, casing and fixed equipment. Under the contract the well is drilled at a specified rate per foot, so that when this practice is followed it is possible to estimate in advance the cost of the well to the producer with fair precision. It is also customary to contract cementing and well-shooting jobs, in the former case at a flat rate per job ($250 in the California fields), the contractor furnishing labor and cementing equipment, and in the latter case at a certain rate per quart of nitroglycerin used. Rig building is often contracted to concerns or individuals specializing in such work.

A considerable part of the rig, drilling equipment, boilers, etc., may be salvaged when the well is completed, being unnecessary after it is

placed on production. On completion of a producing well some operators dismantle the drilling derrick and replace it by a lighter and less expensive production derrick. A smaller power plant than is necessary in drilling will more efficiently serve the operating requirements. Estimated first cost of a well may often be reduced by from 10 to 15 per cent if salvage value is taken into consideration, as is proper if the material and equipment removed may be used in drilling other wells or has a definite sales value. If the well is a dry hole and the casings can be pulled



(*After B. Barkis and R. D. Copley in Am. Petroleum Inst. Bull.* 210.)

FIG. 110.—Drilling progress charts for typical California oil fields.

and the engine, boilers, rig and derrick removed, a much greater reduction will result—often as high as 30 per cent of the first cost.

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CHAPTER VIII

CASING, CASING APPLIANCES AND CASING METHODS

Purpose of Casing.—It is necessary to case wells drilled for oil for three reasons: first, to prevent the walls from caving and burying the drilling tools and well equipment; second, to exclude water from the oil-producing formations; and third, to prevent waste of oil and gas, either into the atmosphere or through seepage into porous strata overlying the productive horizons. While some formations, particularly the harder sandstones and limestones, stand with vertical walls for depths of hundreds of feet and for long periods of time without casing of any sort, most of the softer rocks, such as the sands, shales and clays, cave readily. In some cases it is impossible to drill more than a few feet ahead of the casing without endangering the tools. Water is not always found in quantity in the rocks overlying the oil-producing horizons, but when it does occur it is necessary to seal it off back of a column of pipe, care being taken to so fill the space around the bottom of the pipe that water does not find its way down into the oil sands. Water entering the oil sands in quantity is found to be detrimental to continued production and greatly lessens the ultimate recovery. In an uncased hole gas and oil may escape from the well into porous dry strata and become dissipated through them so that complete recovery can never be effected. Furthermore, in an open hole it is impossible to prevent free escape of gas and oil into the atmosphere at the well mouth. In order to avoid these occurrences, practically all wells drilled for oil are cased with at least one column of pipe, and in many cases several telescoping strings are provided, one within the other, to make proper provision for water exclusion and to adapt the well lining to the necessary changes in the diameter of the bore as depth increases. The cost of casing is usually the greatest single item of expense in the cost of an oil well, and the selection of pipe weights and sizes, the planning of the casing installation, and the insertion and manipulation of the casing in the well are among the most important problems encountered.

Requirements of Oil-well Casing.—In order to serve the purposes outlined above effectively, the casing used must be of adequate strength to resist the collapsing pressures to which it is subjected as a result of hydrostatic and earth pressure and to prevent "parting" or pulling apart under its own weight, or under extreme tension applied by pulling the pipe up when it is under considerable "friction" against the walls of the

well. Frictional resistance between the casing and the walls is in large part dependent upon the design of the joints by means of which sections of pipe are connected. The type of joint used must be such that in addition to adequate strength it may be readily coupled and uncoupled when desired. When in the well, the casing should present as smooth a surface as possible, on both the outside and inside—on the outside to reduce friction between the metal and the walls of the well and on the inside to prevent the drilling tools and other casings from catching as they are lowered through. The casing must be water-tight, particularly if it is to be used in sealing off water, and it should, in so far as is possible, be made of a material that resists corrosion when in contact with saline ground waters. The material must also be hard and rigid enough to resist abrasion and distortion by contact with the rock walls of the well or the drilling tools. The walls of the pipe must be as thin as is consistent with the necessary strength, in order to avoid undue loss in effective working area within the well. Since considerable amounts of casing are necessary in oil-field development, it must be available at a price which will not be prohibitive.

TYPES OF CASING

Cylindrical casings of a variety of different types are used in oil-well service. The commonly used form is made up of sections averaging 20 ft. in length, connected with threaded collar joints. Light casings suitable only for shallow depths are frequently made of sheet metal rolled into cylindrical form with the joints riveted or welded. This is called "stove-pipe," and sometimes the metal cylinder so formed is corrugated circumferentially for greater strength against deformation and collapse.

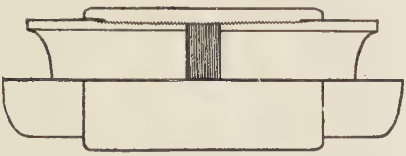
Screw-joint Casing

This casing may be had in a variety of sizes and thicknesses and also with several different types of joints. The collared-joint variety is generally preferred because of its greater strength, but it has the disadvantage that the collars project on the outside of the pipe, increasing the friction against the walls of the well and reducing the effective working diameter. The "inserted" and "flush-jointed" types of screw casing are designed to minimize these difficulties but are structurally weak.

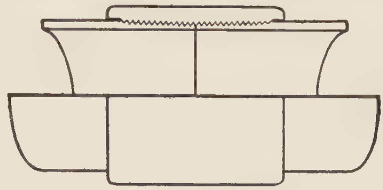
The cutting of a thread on the end of a pipe weakens it by reason of the metal removed in forming the thread. A section of properly made pipe is always weakest at the base of the threads, for here the metal is thinnest. With the purpose of constructing screw-joint pipe of uniform strength throughout, some manufacturers are now making "upset-end" pipe, in which the metal is thicker at the ends by an amount equal to or greater than the depth of the threads (see Fig. 111). The additional metal is sometimes placed on the inside of the pipe (as in rotary drill pipe) but preferably on the outside if it is to be used for well tubing. Great loss of working diameter is characteristic of upset-end casings.

Methods of Manufacturing Well Casing.—Casings used in oil-well service are classified into two different groups depending upon the method of manufacture: welded and seamless. In the production of lap-welded casing, the most widely used

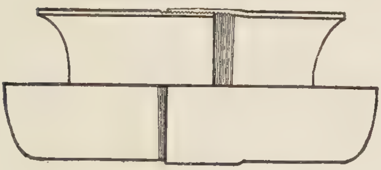
variety, appropriate for all ordinary conditions, long sheets of metal of proper gage and width ("skelp") are longitudinally rolled into cylindrical form and the edges welded. To provide sufficient width of contact for proper welding, the edges of the plates are scarfed and when the skelp is rolled into cylindrical form are allowed to overlap slightly. Butt-welded pipe, in which the edges of the plate are left square and welded without overlap, is made only in sizes smaller than 3 in. and is not appro-



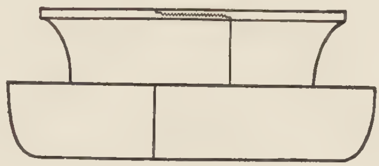
California Diamond B X casing.



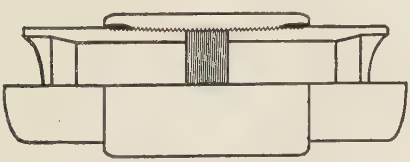
Drive pipe.



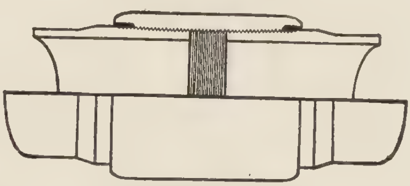
Inserted joint casing.



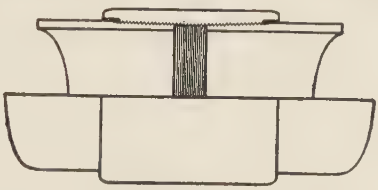
Flush-jointed casing.



Internally upset rotary drill pipe.



Externally upset tubing.



Oil well tubing and coupling.

(Redrawn from illustrations in handbook published by National Tube Co.)

FIG. 111.—Types of joints used on oil-well casing and tubing.

priate for oil-well service because of its inherent weakness. After welding, the tubes are passed through cross rolls which straighten and give them a smooth exterior surface. They are then allowed to cool slowly and uniformly in order to avoid internal strain. When cool, the rough ends are cut off, and, later, threads are cut on each end. Seamless casing, a variety of exceptional strength, is used in deep wells or under conditions where stresses are developed in excess of the working load that may be safely imposed on lap-welded pipe. Seamless pipe is made by piercing a solid round billet longitudinally and rolling out the resulting thick-walled tube on a mandrel. It is necessarily more expensive than the lap-welded variety.

Properties of Materials Used in Manufacture of Oil-well Casings.—Both wrought iron and steel are used in the manufacture of well casing. Manufacturers of wrought-iron pipe claim that their product is less susceptible to corrosion, has superior welding

and threading qualities and develops greater resistance to fatigue. Much of this, however, is disputed by the manufacturers of steel pipe. Certainly, where strength, ductility and durability are important, steel is preferable. By far the greater amount of casing and tubing used in oil-well service is of steel, and in the deeper territory, now being exploited, steel is essential.

Either Bessemer, open-hearth or electric-furnace steel may be used in the manufacture of lap-welded casing, but the open-hearth variety is by far the most widely employed. Bessemer steel is preferred by some manufacturers because it welds readily and machines easily. Steel used in seamless casing is customarily made by the basic open-hearth process. Four different grades of seamless casing are recognized, designated A, B, C and D, each possessing successively higher tensile strength and yield point in the order named. The several grades differ in carbon, manganese, phosphorus and sulphur content. Steels of low-carbon content (0.1 to 0.2 per cent) have characteristically low tensile strength but high ductility. High-carbon steels (0.4 to 0.5 per cent), with tensile strengths as high as 110,000 lb. per square inch, are comparatively hard and brittle. Even higher tensile strength would be possible by increase in carbon content and with special methods of heat treatment but only at the expense of ductility, which is also an essential quality in well casing. High strength may also be achieved through the use of special alloy steels containing higher than normal percentages of manganese, chromium or nickel, but such steels are costly and pipe made from them difficult of manufacture. A small percentage of copper in steel confers added resistance to corrosion.

In an effort to standardize casing materials, the American Petroleum Institute has adopted specifications which prescribe definite limits on the chemical constitution of the steel used. Table XXIX gives permissible percentages of manganese, phosphorus and sulphur for the several grades of steel. Wrought iron used in casing manufacture should not contain more than 0.16 per cent of impurities, according to A.P.I. specifications, considering carbon, sulphur, phosphorus, silicon, copper and manganese as impurities. Tensile strengths, yield points and elongations prescribed for the several grades of steel and wrought iron used in casing manufacture are presented in Table XXX.

Pipe-trade Customs.—Well casing is shipped from the mills in sections averaging 20 ft. in length, with an iron or steel coupling on one end and a rough thread-protecting collar on the other. The threaded ends are "doped" or greased to protect the pipe against corrosion during transit. Sizes of casing and tubing are designated by both diameter and weight, as several weights are made in each size. For each size the external diameter is constant, the thickness of walls and internal diameter varying with the weight.

Table XXIX.—Chemical Analyses of Grades of Steel Used in Casing Manufacture*

	Bessemer welded	Open-hearth welded		Seamless			
		Class I	Class II (rephos.)	Grade A	Grade B	Grade C	Grade D
Manganese, per cent	.30–.60	.30–.60	.30–.60	.30–.60	.35–1.50	.35–1.50	†
Phosphorus, not over, per cent	.11	.045	.08	.04	.04	.04	.04
Not less than, per cent	....	....	.045				
Sulphur, not over, per cent	.065	.06	.06	.06	.06	.06	.06

* As specified by A.P.I. standards.
† Manufacturer's option.

Table XXX.—Tensile Strengths, Yield Points and Elongations of Several Grades of Steel and Wrought Iron Used in Casing Manufacture*

	Steel							Wrought iron	Open-hearth iron
	Bessemer welded	Open-hearth welded		Seamless					
		Class I	Class II (rephos.)	Grade A	Grade B	Grade C	Grade D		
Tensile strength, lb. per sq. in.	50,000	45,000	48,000	48,000	70,000	75,000	95,000	42,000	42,000
Yield point, lb. per sq. in.	30,000	25,000	28,000	30,000	40,000	45,000	55,000	24,000	24,000
Elongation in 8 in., per cent	20	22	20	......	......	......	......	12	20
Elongation in 2 in., per cent	......	......	......	40	25	20	18		

* Minimum values specified by A.P.I. standards.

The American Petroleum Institute, in attempting to standardize casing used in the oil industry, has adopted a series of sizes and weights of casing in which all dimensions are prescribed (see Table XXXI). American Petroleum Institute standard casings are always designated by their external diameter and average weight per foot with threads and couplings spaced at 20-ft. intervals. The manufacturing process does not permit of absolute precision in weight and dimensions, and reasonable varia-

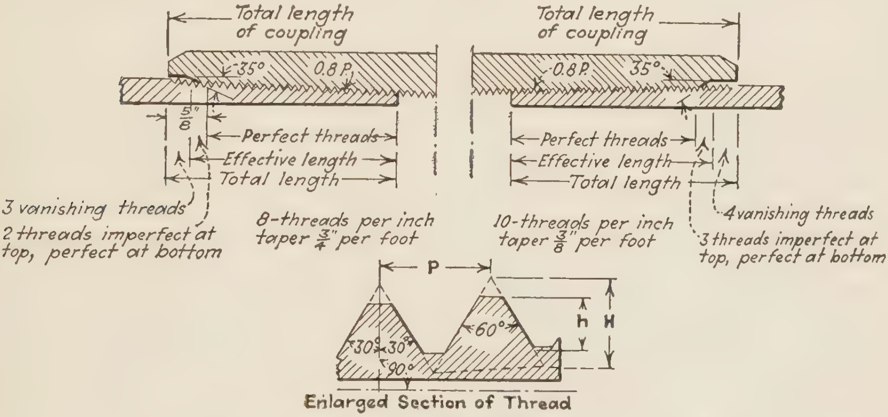


Fig. 112.—A.P.I. standard casing threads and couplings.

tions from the prescribed standards are allowed. The weight of any length of pipe shall not vary more than 3½ per cent under or 6½ per cent over that specified. Carload weights may not be more than 1¾ per cent under the nominal weight. The average length of a carload lot shall not be less than 20 ft. per joint. Individual joints less than 16 ft. in length are not permitted, and not more than 5 per cent of any carload lot may be less than 18 ft. in length. American Petroleum Institute specifications provide that the finished pipe must be "reasonably straight and free from injurious defects, such as burnt material, bad welds, sand pits, ball cuts, pits, cinder spots, liquor marks, blisters, slivers and laminations. The threading on the pipe must be free from tears, shoulders, cuts or any defects which may break the continuity of the thread."

Physical tests are applied to all casing before leaving the mill to make certain that it conforms to specification requirements. In addition to the matters suggested above, hydrostatic tests are applied to make certain that the pipe will sustain a specified minimum bursting pressure. A drift test, made by passing a cylindrical mandrel of a specified diameter only slightly less than the inside diameter, through each joint

TABLE XXXI.—AMERICAN PETROLEUM INSTITUTE STANDARD CASING SIZES, WEIGHTS AND TEST PRESSURES

(Originally established by the Committee for Uniform Clearance)
"Size" of A.P.I. casing indicates outside diameter

Size, in.	Diameter, in.				Weight per foot, lb.		Couplings		Test press., lb. per sq. in.			
									Steel			
	External O.D.	Internal I.D.	Thickness, in.	Threads, number per inch	Plain ends	Threads and couplings	Diameter, in.	Length, in.	Lap weld and Grade A seamless	Grades B and C seamless	Grade D seamless	Open-hearth iron and wrought iron
4¾	4.75	4.082	.334	10	15.752	....	....	7	2,100	2,500	2,800	1,900
5¾	5.75	5.29	.23	10	13.559	14.00	6.5625	7½	1,200	1,500	2,000	1,100
5¾	5.75	5.19	.28	10	16.357	17.00	6.5625	7½	1,500	1,800	2,400	1,300
5¾	5.75	5.09	.33	10	19.102	19.50	6.5625	7½	1,700	2,100	2,800	1,500
5¾	5.75	4.99	.38	10	21.793	22.50	6.5625	7½	2,000	2,400	2,800	1,800
*8⅛	8.125	7.485	.32	10	26.674	28.00	9.0937	8½	1,200	1,500	2,000	1,100
*8⅛	8.125	7.385	.37	10	30.645	32.00	9.0937	8½	1,400	1,700	2,300	1,200
*8⅛	8.125	7.285	.42	10	34.562	35.50	9.0937	8½	1,600	1,900	2,600	1,400
*8⅛	8.125	7.185	.47	10	38.425	39.50	9.0937	8½	1,800	2,100	2,800	1,500
10¾	10.75	10.05	.35	8	38.875	40.50	11.75	8½	1,000	1,200	1,600	900
10¾	10.75	9.95	.40	8	44.215	45.50	11.75	8½	1,100	1,400	1,900	1,000
10¾	10.75	9.85	.45	8	49.502	51.00	11.75	8½	1,300	1,500	2,100	1,100
10¾	10.75	9.76	.495	8	54.214	55.50	11.75	8½	1,400	1,700	2,300	1,200
13⅜	13.375	12.715	.33	8	45.976	48.00	14.375	9	800	900	1,200	700
13⅜	13.375	12.615	.38	8	52.739	54.50	14.375	9	900	1,100	1,400	800
13⅜	13.375	12.515	.43	8	59.449	61.00	14.375	9	1,000	1,200	1,600	900
13⅜	13.375	12.415	.48	8	66.105	68.00	14.375	9	1,100	1,300	1,800	1,000
16	16.00	15.375	.3125	8	52.357	55.00	17.00	9	600	.....	1,000	500
16	16.00	15.250	.375	8	62.579	65.00	17.00	9	700	.....	1,200	600
16	16.00	15.125	.4375	8	72.716	75.00	17.00	9	900	.....	1,400	800
16	16.00	15.010	.495	8	81.969	84.00	17.00	9	1,000	.....	1,500	900
18⅝	18.625	17.855	.385	8	75.000	78.00	19.75	9	650	.....	1,000	500
18⅝	18.625	17.755	.435	8	84.508	87.50	19.75	9	700	.....	1,200	600
18⅝	18.625	17.655	.485	8	93.962	96.50	19.75	9	800	.....	1,300	700
21½	21.50	20.71	.395	8	89.034	92.50	22.625	9	600	.....	900	500
21½	21.50	20.61	.445	8	100.067	103.00	22.625	9	650	.....	1,000	600
21½	21.50	20.51	.495	8	111.046	114.00	22.625	9	700	.....	1,200	600
24½	24.50	23.75	.375	8	96.622	100.50	25.625	9	500	.....	800	400
24½	24.50	23.65	.425	8	109.278	113.00	25.625	9	600	.....	900	500

* This size inactive; available on special order only.

Table XXXI.—American Petroleum Institute Standard Casing Sizes, Weights and Test Pressures.—(*Continued*)

A.P.I. Supplementary Standard Casing

(Special sizes selected from those now in use and added on request of certain districts)

Size, in.	Diameter, in. External O.D.	Diameter, in. Internal I.D.	Thickness, in.	Threads, number per inch	Weight per foot, lb. Plain ends	Weight per foot, lb. Threads and couplings	Couplings Diameter, in.	Couplings Length, in.	Test press., lb. per sq. in. Steel Lap weld and Grade A seamless	Test press. Steel Grades B and C seamless	Test press. Steel Grade D seamless	Test press. Open-hearth iron and wrought iron
4¾	4.75	4.082	.334	10	16.00	15.752	5.364	6⅝	2,100	2,500	2,800	1,900
6⅝	6.625	6.049	.288	10	20.00	19.491	7.390	7⅝	1,500	1,600	2,200	1,200
6⅝	6.625	5.921	.352	10	24.00	23.582	7.390	7⅝	1,600	2,000	2,700	1,400
6⅝	6.625	5.855	.385	10	26.00	25.658	7.390	7⅝	1,700	2,100	2,800	1,500
6⅝	6.625	5.791	.417	10	28.00	27.648	7.390	7⅝	1,900	2,300	2,800	1,700
7	7.000	6.456	.272	10	20.00	19.544	7.656	7⅝	1,200	1,400	1,900	1,000
7	7.000	6.398	.301	10	22.00	21.535	7.656	7⅝	1,300	1,600	2,200	1,100
7	7.000	6.336	.332	10	24.00	23.643	7.656	7⅝	1,400	1,800	2,400	1,300
7	7.000	6.276	.362	10	26.00	25.663	7.656	7⅝	1,600	1,900	2,600	1,400
7	7.000	6.214	.393	10	28.00	27.731	7.656	7⅝	1,700	2,100	2,800	1,500
7	7.000	6.154	.423	10	30.00	29.712	7.656	7⅝	1,800	2,200	2,800	1,600
7⅝	7.625	6.969	.328	8	26.40	25.562	8.500	8⅛	1,300	1,600	2,200	1,100
7⅝	7.625	6.875	.375	8	29.70	29.036	8.500	8⅛	1,500	1,900	2,500	1,300
7⅝	7.625	6.765	.430	8	33.70	33.042	8.500	8⅛	1,700	2,100	2,800	1,500
8⅝	8.625	8.017	.304	8	28.00	27.016	9.593	8⅛	1,100	1,300	1,800	1,000
8⅝	8.625	7.921	.352	8	32.00	31.101	9.593	8⅛	1,300	1,500	2,000	1,100
8⅝	8.625	7.825	.400	8	36.00	35.137	9.593	8⅛	1,400	1,700	2,300	1,200
8⅝	8.625	7.775	.425	8	38.00	37.220	9.593	8⅛	1,500	1,800	2,500	1,300
8⅝	8.625	7.651	.487	8	43.00	42.327	9.593	8⅛	1,700	2,100	2,800	1,500
9	9.000	8.290	.355	8	34.00	32.777	10.010	8⅛	1,200	1,500	2,000	1,100
9	9.000	8.196	.402	8	38.00	36.914	10.010	8⅛	1,300	1,700	2,200	1,200
9	9.000	8.150	.425	8	40.00	38.922	10.010	8⅛	1,400	1,700	2,400	1,200
9	9.000	8.032	.484	8	45.00	44.020	10.010	8⅛	1,600	2,000	2,700	1,400
9⅝	9.625	8.921	.352	8	36.00	34.861	10.625	8⅛	1,100	1,400	1,800	1,000
9⅝	9.625	8.835	.395	8	40.00	38.938	10.625	8⅛	1,200	1,600	2,100	1,100
9⅝	9.625	8.755	.435	8	43.50	42.695	10.625	8⅛	1,400	1,700	2,300	1,200
11¾	11.75	11.000	.375	8	47.00	45.557	12.866	8⅛	1,000	1,200	1,600	800
11¾	11.75	10.880	.435	8	54.00	52.568	12.866	8⅛	1,100	1,400	1,900	1,000
11¾	11.75	10.772	.489	8	60.00	58.811	12.866	8⅛	1,200	1,500	2,100	1,100

of casing, gives assurance that the pipe is truly cylindrical in form and free from dents, internal blisters or other projections. Tension tests and flattening tests are also applied to the "crops" cut from the ends of the tubes during the process of manufacture. Tests are also applied to determine the alignment and dimensional accuracy of the threads.

Pipe threads used on oil-well casings are a modified style of the Briggs standard, 60 deg., V-form (see Fig. 112). Maximum strength in a threaded joint is secured by

a proper balance between the thickness of the metal walls of the pipe and the "pitch" or spacing of threads. It is apparent that the thickness of metal resisting tensional stress, left at the base of the threads, will be greater for shallow, closely spaced threads than for deep, widely spaced threads; but the tendency of the joint to pull apart by shearing or "stripping" of the threads will be greater for a shallow than for a deep thread. American Petroleum Institute standards provide that threads used on casings 8⅝ in. in diameter or less shall have a pitch of 10 threads per inch, while sizes of 8⅝ in. or more are cut with 8 threads per inch. As many as 11½ or even 14 threads per inch must be used on some of the thinner walled casings where the thickness of metal left at the roots of the threads would be unduly reduced by an 8- or 10-thread cut.

In order that the pipe sections may tighten securely in the collars, the thread is cut on a slight taper with the axis of the tube. American Petroleum Institute standards specify this taper as ⅜ in. per foot for casings 8⅝ in. in diameter or less and ¾ in. per foot for sizes of 8⅝ in. or larger. The length of the thread is such that when two tubes are tightly screwed into a coupling, their ends are 1¼ in. apart. The threaded section terminates in four imperfect threads which vanish into the contour of the cylindrical surface on which they are cut (see Fig. 112).

Casing collars are of special design, being generally longer and heavier than the type of coupling used on ordinary standard pipe (see Fig. 112). The material used in their manufacture may be either wrought iron or steel, and either seamless or welded, but if steel is used, couplings should be electroplated with lead or subjected to some process of heat treatment which will minimize the galling tendency of threads cut on steel. To aid in starting the pipe into the coupling, a recess is turned in each end of the collar. This also serves to protect the end threads, which start from the bottom of the recess at either end, tapering toward the center to conform with the taper of the threads on the pipe. The recessed ends of the collar fit snugly over the unthreaded casing and increase to some extent the rigidity and security of the joint.

Types of Collared-joint Casing.—A variety of casings of the collared-joint type is available on the market, differing from each other chiefly in weight or thickness. Operators in different regions have developed a preference for particular brands of pipe which are supposedly best adapted to the conditions to be met. For example, a casing which is marketed under the name of Diamond B X has been widely used in the California fields. It is somewhat heavier than other grades of casing extensively used elsewhere and is better adapted to deep-well conditions than lighter weight pipe. Boston and South Penn casings are lighter grades that have been preferred in the Appalachian region and in certain of the Mid-Continent fields. Though still available from the pipe manufacturers, these grades are now less used than formerly because of adherence of most oil producers to the A.P.I. standards. American Petroleum Institute casing sizes are adaptable to all ordinary conditions. Special casings of unusual size or strength may be made to order to fit particular requirements, at a cost but little higher than that of standard sizes.

Drive pipe is a collared-joint type of casing, somewhat heavier than the average, that is designed particularly for use under circumstances which require heavy driving (hammering) on the upper end of the column to force it into the well. This necessity arises in tight holes where the well is somewhat smaller than its intended diameter, or where material caves from the walls of the well about the pipe until the friction so developed prevents free movement. In order that the pipe may be driven from the surface without placing undue strain on the collars, the taper and length of the threads are such that the ends of the joints butt together at the centers of the collars. While such a pipe is well adapted to driving, it is apt to be loosened in the collars in the process and often parts when an upward pull is applied. The development of modern methods of rotary drilling in which the casing is left fairly free of the walls of the

well has largely removed the necessity for using drive pipe; but in former years when the cable tools were used in drilling through unconsolidated formations, large quantities of it were employed.

Upset-end Pipe.—The advantages of upset-end pipe, in which the thickness of the walls is increased at the ends of the tubes where the threads are cut, so that under tensional stress it is of uniform strength throughout, have already been suggested. Such pipe is used in the oil industry chiefly as rotary drill pipe (see Table XX and Fig. 79) and in small sizes as oil-well tubing, though to a limited extent also as well casing. Upset-end pipe used for rotary drilling has the additional metal on the inside, while with well casing and tubing it is on the outside. Figure 113 illustrates the approved type of threaded joint.

Inserted-joint Casing.—When a well is shallow and a light casing is all that is needed to sustain the walls, inserted-joint casing may be advantageously employed.

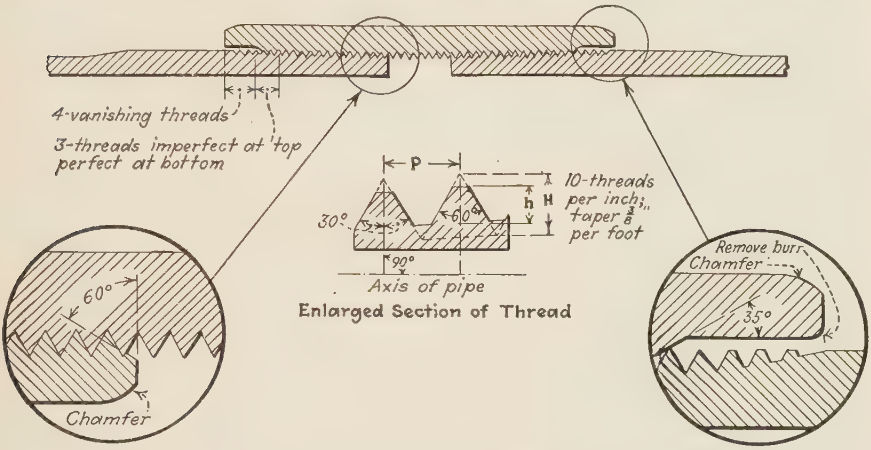


Fig. 113.—A.P.I. standard upset-end casing threads and couplings.

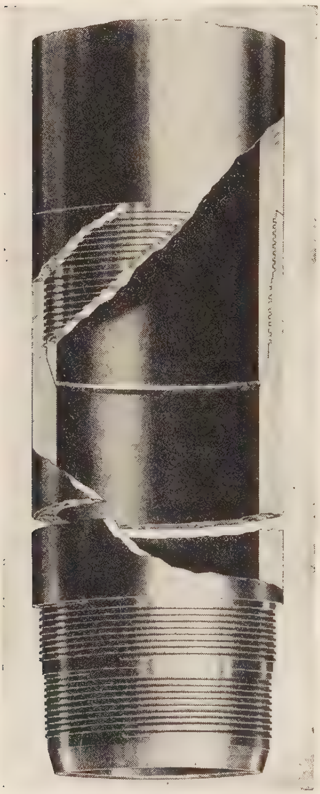
This type of joint is often used for liners and is also preferred in cases where it is necessary to economize in working space within a well of small diameter. In this type of casing one end of the tube is expanded and internally threaded, so that the end of one joint receives the externally threaded and unexpanded end of another joint (see Fig. 111). The threads are only slightly tapered. Modified forms have also been developed in which the outer half of the joint is expanded and the inner half is "cressed." In another variety a faced ring is screwed on the externally threaded end, against which the outside or expanded half of the joint butts when the parts are screwed together. This prevents the expanded end from splitting and adds to the security of the joint to such an extent that if necessary it can be lightly driven.

Flush-jointed casing is made by turning down and cutting a thread on one end of a tube, and boring out and threading internally the end of another tube (see Fig. 111). The end of one tube thus screws into the other without the necessity for a collar, and the joint has no visible edges or corners on either the outside or inside. Such a joint is particularly useful where the diameter of a well has become so reduced that it is important to use a casing that occupies the smallest possible space. Because of its smooth exterior surface it is useful also in casing off loose sands which tend to cave and pack around the couplings of ordinary pipe. The joint is inherently weak, however, as a result of cutting away half of the metal on each tube at the joint. The threads must be shallow and tend to pull apart readily. Flush-jointed casing is screwed together until the ends of the tubes butt together at the center of the joint.

In this condition it is water-tight, though not recommended for water exclusion, and can be lightly driven; but any deflection from the vertical will generally result in fracture at the base of the threads. It is rarely used in oil-field operations. Figure 114 is illustrative of a special type of step-threaded, flush-jointed well casing that has certain advantages over the ordinary type.

Welding Joints in Oil-well Casing Installations

The success attained in welding line pipe for the transmission of oil and gas has led to the welding of oil-well casings as a substitute for the screw joint. It is perfectly feasible to weld wrought iron or steel pipe in the derrick with the aid of the oxyacetylene torch, and the resulting joint is as strong as is possible with any form of screw joint if the welding is properly done. Plain-end pipe (without threads) is used, with ends beveled on the outside, the joints being butt-welded above the derrick floor as they enter the well (see page 315). Joining pipe in this way is slower, however, than when threaded collars are used, and it is impossible to remove a string of welded casing from the well without cutting the sections apart. The fire risk involved in using a torch about the mouth of a well, which may be producing inflammable oil or gas, must also be considered.



(*Doheny-Stone Drill Co.*)
Fig. 114.—"Hydril" flush-jointed casing.

The cost of a welded string of casing is about the same as that of ordinary collared-joint casing, the saving in cost of threading and collars being approximately offset by the cost of preparing the joints and welding them together. The method is used particularly in welding "liners," the column of casing which penetrates the oil-producing zone; but it has also been successfully used in welding larger pipes, particularly in redrilling jobs where it has been necessary to "sidetrack" an old column of casing, a condition which might lead to interlocking of collars on the two strings. In fields where the producing formation is a loose sand, the material tends to pack about the collars of ordinary casing, making removal of the liner difficult particularly if the hole is crooked. Much of this trouble is overcome by the use of a welded liner. In some California wells, welded strings of 8¼- and 10-in. casings 1,100 ft. in length have been successfully inserted. Some operators make a practice of spot welding the collars on ordinary casing to prevent the joint from loosening in the well.

Sheet-metal Casings

Riveted casing (stovepipe) is made of thin sheets of wrought iron or steel rolled into cylindrical form and riveted at the seams (see Fig. 115). The individual joints are 2 or 3 ft. long and are usually made of two sheets of metal, one cylinder within another, and so placed with respect to each other that the end of one cylinder is just opposite the center of the other. This results in the inside cylinder projecting for

half its length at one end, leaving a corresponding recess within the outer cylinder at the opposite end. When such joints are put together, the projecting inside sheet of one joint is forced into the center of the outside sheet of another, until the inside sheets of the two joints butt together. The result is a continuous, double-walled cylinder. Considerable friction develops between joints when they are forced together, and it is customary to increase this by denting the outer cylinder against the inner with the point of a sharp pick. The frictional contact between joints, thus developed, is often all that is provided to hold them together. Occasionally, however, when a long column of stovepipe is to be placed in a well and there is danger of the column pulling apart under its own weight, the joints will be riveted together. This is accomplished

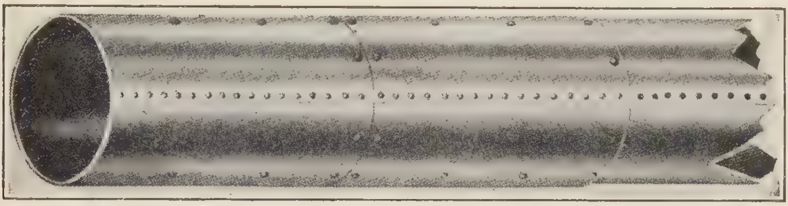


Fig. 115.—Riveted casing or "stovepipe."

by lowering a close-fitting mandrel inside the pipe to serve as an anvil and driving the rivets against the mandrel through holes previously drilled and countersunk on the inside.

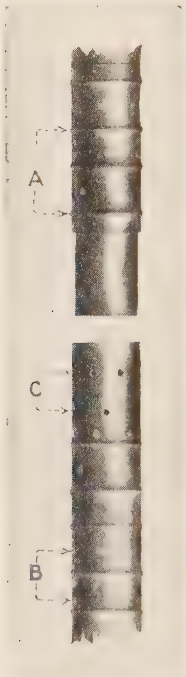
Riveted casing is generally used in wells of large diameter, say 12 in. or greater, though it may be had in sizes as small as 4 in. Sizes up to and including 20 in. are regularly carried by the manufacturers, and larger sizes may be made to order for wells of exceptional diameter. In the Russian fields where, in years past, this kind of casing was used almost exclusively, casings as large as 36 in. in diameter are not uncommon. The metal sheets used in forming stovepipe vary from 1/8 to 5/16 in. in thickness, the sheets being cut to proper size and all rivet holes punched and countersunk before the cylinders are rolled. The pipe, ready for insertion into the well, may be had from the manufacturers or supply dealers in either single joints or in sections ranging in length from 10 to 21 ft., the individual joints making up each section being riveted together at the joints as well as along the seams. Riveted casing is not ordinarily water-tight, though it can be made approximately so by careful caulking of all seams and joints. However, it is not ordinarily heavy enough to withstand any great hydrostatic head that may build up behind the casing in wet formations.

It is customary to reinforce the first joint (or "starter joint") of a column of stove pipe, either by riveting on a steel shoe or by constructing the first joint of three or four sheets of metal instead of two. The latter type of reinforcement is generally preferred because of the smaller clearance necessary. Such reinforcement assists in preventing abrasion and distortion of the lower end of the pipe by contact with the walls of the well.

Riveted casing is only intended for light service and is seldom used at greater depths than 800 ft. because of its tendency to pull apart under its own weight. However, single columns of 16-in. stovepipe over 1,000 ft. long have been successfully placed in wells under favorable conditions. For the same reason, when once started into the well, it cannot usually be raised if there is friction against the walls. It can only be driven lightly since the joints have a tendency to telescope and buckle; or if the lower end of a column is hanging freely in the well, it may be jarred off by the resulting vibration. It is easily deformed by pressure from the walls or in passing through a flat hole. The chief advantages of riveted casing are its smooth exterior

surface, small space occupied in the well and lower cost. Because of its smooth outer surface, it is particularly adapted to casing off loose, sandy surface strata which tend to cave and bind against the couplings on collared-joint casing. Loss in effective working diameter within the well is reduced to a minimum through the use of this class of casing.

Other Varieties of "Conductor" Casing.—In addition to stovepipe, other forms of light casings are available for use as surface "strings" where no very great pressures must be contended with and where a water-tight lining for the well is not essential.



(*Union Tank and Pipe Co.*)

FIG. 116.—Hercules conductor casing.

A, corrugations giving security against lateral stress; *B*, button welds; *C*, shop-punched holes for welding.

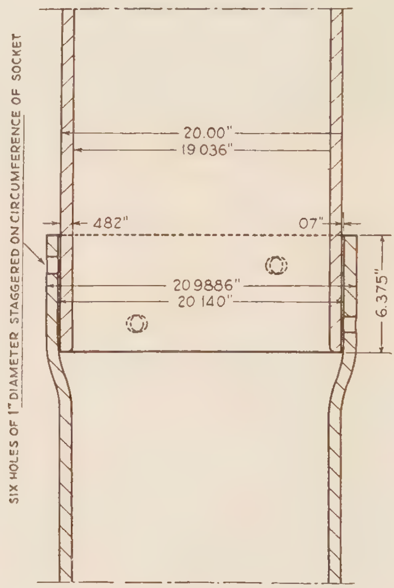


FIG. 117.—"Astco" slip-joint conductor casing.

(Dimensions given are for 20-in. outside diameter, 104-lb. casing.)

The larger sizes of collared-joint screw casing are unnecessarily heavy and expensive for such installations, and considerable economy is possible through the use of thin-walled conductor casing. Hercules casing (see Fig. 116) has been a popular type in the California fields, where surface strings ranging from 16 to 30 in. in diameter must be set at depths up to 1,200 ft. This is a heavy, sheet-metal casing in which the seams are welded and the individual joints are held together by a patented welded rivet. Circumferential corrugations give security against deformation. It is available from the manufacturers in 20-ft. lengths, which are riveted and welded together as they are lowered into the well. A thin-walled seamless steel casing, utilizing inserted joints designed for welding, is also on the market in sizes up to 20-in. diameter (see Fig. 117). This is delivered at the well in joints ranging from 35 to 45 ft. in length, and on insertion into the well the joints are spot-welded with the acetylene torch through holes

bored in the outer portion of the bell. Because of its superior strength, it may be carried to greater depths than other forms of light conductor pipe. Casings of these special types are often assembled and placed in the wells on a contract basis by experienced welding crews in the employ of the manufacturers.

CASING APPLIANCES

The installation and manipulation of casing in the well and within the derrick require the use of a variety of special appliances worthy of brief description. These include casing elevators, hoisting blocks, casing hooks

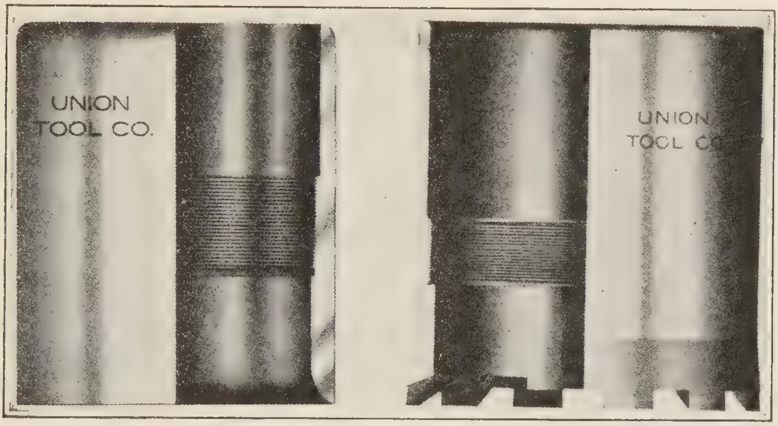
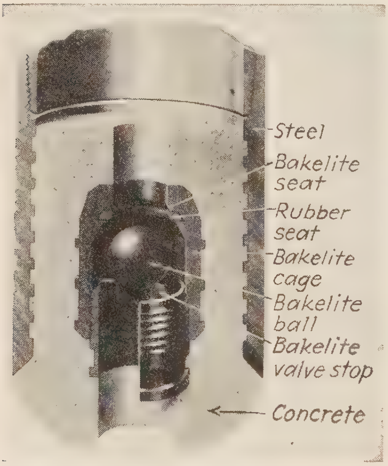


Fig. 118.—Types of casing shoes.
Left, common form; right, Baker shoe.

and spiders for lifting, lowering and suspending a column of pipe; casing shoes attached to the lower end of a column of pipe to aid it in cutting its way through projections on the walls of the well and to reinforce the lower end of the column against damage thereby; casing tongs for screwing sections of pipe together; drive heads and clamps used in driving casing into a tight hole; and casing jacks useful in applying a powerful lifting force to casing that has become partially frozen by friction against the walls of the well. In addition to these, there are numerous other devices, some of which are described below, while others pertaining particularly to fishing operations are reserved for a later chapter.

Casing Shoes.—It is customary to place on the outside of the bottom of every column of casing lowered into the well a reinforcing shoe of steel, specially formed to prevent distortion and abrasion of the pipe, and to aid it in cutting a way for itself past minor obstructions on the walls. The lower edge is beveled to a blunt cutting edge on the outer circumference. Casing shoes are somewhat larger in outer diameter than the collars on the casing to which they are attached, in order to insure free passage of the pipe for any opening through which the shoe has passed. They are usually about 1 in. thick, from 10 to 16 in. long and weigh in the case of the larger sizes from 100 to 200 lb. There are several patterns

(see Fig. 118) some of which are designed to screw on the bottom joint of casing, while others are shrunk on. The Texas pattern is both screwed and riveted to the casing. The Baker shoe has a series of square teeth cut on the lower end. By rotating a casing equipped with this shoe, the casing is capable of cutting a way for itself past minor obstructions. When pipe is to be worked down through hard rock, such a shoe offers a considerable advantage. The material used in the manufacture of casing shoes is preferably a good grade of hardened plow steel. Casing shoes designed to screw on the casing usually have a narrow recess, turned in the upper end above the threads, and a shoulder below the threads. The casing screws into the shoe until it butts against the shoulder, and the annular space above the threads formed by the recess between the casing and the shoe is filled with molten lead or babbitt metal. This strengthens the screw joint and prevents the shoe from becoming detached in the well. The shoe provided must be especially heavy when driving of the pipe will be necessary.



(*Baker Oil Tools Co.*)
FIG. 119.—Baker cement float shoe.

For use in the unconsolidated formations of the California fields, some operators construct unusually heavy and long casing shoes by shrinking short sections of heavy tubular steel on a joint of casing and dressing the outer surface to a slight taper with a blunt cutting edge at the lower end.

Cement Float Shoes.—Special types of float shoes are available, which are designed to serve the triple functions of reinforcing the lower end of the column of casing, preventing the well fluid from entering the casing so that it may be "floated in"—thus relieving the surface equipment of a large part of the dead load—and facilitating the operation of cementing a column of pipe after it is in place in the well. A sectional view of a type of float shoe popular in the deeper California fields is presented in Fig. 119. In this case, the lower end of the casing shoe is filled with concrete, molded to form a semispherical guide which projects below the shoe. Passages through the concrete and a spherical valve and disk seat permit movement of fluid through the shoe in a downward direction only. The valve is of composition material so that it is lighter than mud fluid and is buoyed upward against its seat by the fluid pressure. Another type differs from the one illustrated in that it has side outlets instead of a bottom outlet. The side outlets are advantageous

when the shoe rests on bottom, in permitting free flow of mud fluid and cement out of the casing during subsequent cementing operations. The concrete and composition valve and seat can be readily drilled up with the tools on resuming drilling operations to lower depths.

Casing Elevators.—In lifting or lowering a joint or column of casing suspended vertically, it is necessary to provide some sort of a clamp which will grip the pipe securely, to which the necessary hoisting tackle may be attached. The device usually employed for this purpose is called a "cas-

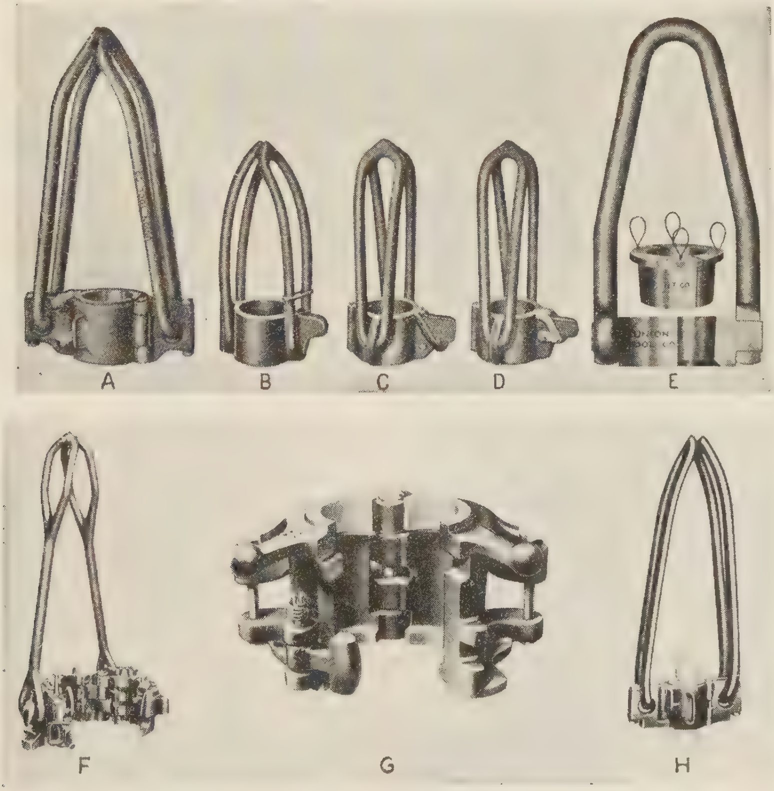


Fig. 120.—Types of elevators.

A, Ideal; *B*, Mannington; *C*, Fair-Mannington; *D*, Fair; *E*, single-link; *F*, *G* and *H* are types of Byron-Jackson elevators; *F*, side-door type equipped with slips and weldless suspension links; *G*, Wilson type, center latch, and *H*, side-door type.

ing elevator" and is so designed that it may be clamped loosely around the pipe below the top collar, the weight of the pipe falling on the lower edge of the collar.

The elevator finds constant use when casing is being inserted into a well, each new joint being lifted from the derrick floor and suspended on the elevator until it is screwed into the collar of the preceding joint, after which the entire column is lowered while suspended on the elevator. Such service requires an elevator that can be rapidly clamped

and unclamped and which suspends the casing vertically so that it can be freely rotated while being screwed into the collar below. It must be of adequate strength to support the weight of the entire column of casing, which may in a long column of large-diameter pipe aggregate 200 tons or more. It is imperative, under the conditions pertaining, that the elevator be so designed that it offers adequate security against accidental opening of the clamps and dropping of the casing while under strain.

Several different patterns of elevators have been designed and are available on the market, differing from each other chiefly in the manner of latching in the locked position. The Fair, Mannington, Ideal "B-J" and Wilson patterns are well-known and commonly used types (see Fig. 120). It will be noted that in each case there is a pair of semicircular clamps hinged at one side and provided with a locking device of some sort at the other. There is also a pair of heavy links, suitably curved to bring the point of support over the center of the pipe, passing through holes in heavy lugs attached to the side of the clamps. The inside diameter of the clamps is slightly greater than the outside diameter of the pipe for which it is intended. One type of elevator has a single link instead of two. The body of the elevator is in this case in one piece and has an opening through it which permits of its passing freely over the casing collar. With the elevator just below the top collar, a split bushing of proper size is slipped into the elevator and around the pipe, furnishing the means of applying a lifting force under the collar. Casing elevators are made of wrought iron or steel and are necessarily of heavy construction, ranging in weight from 200 to upward of 2,500 lb. in the larger sizes of the heavier models. In addition to their use in handling casing, they find application in coupling and uncoupling rotary drill pipe (see page 216) and oil-well tubing.

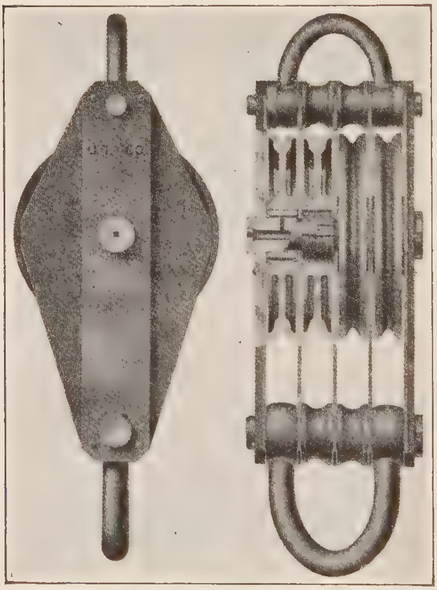
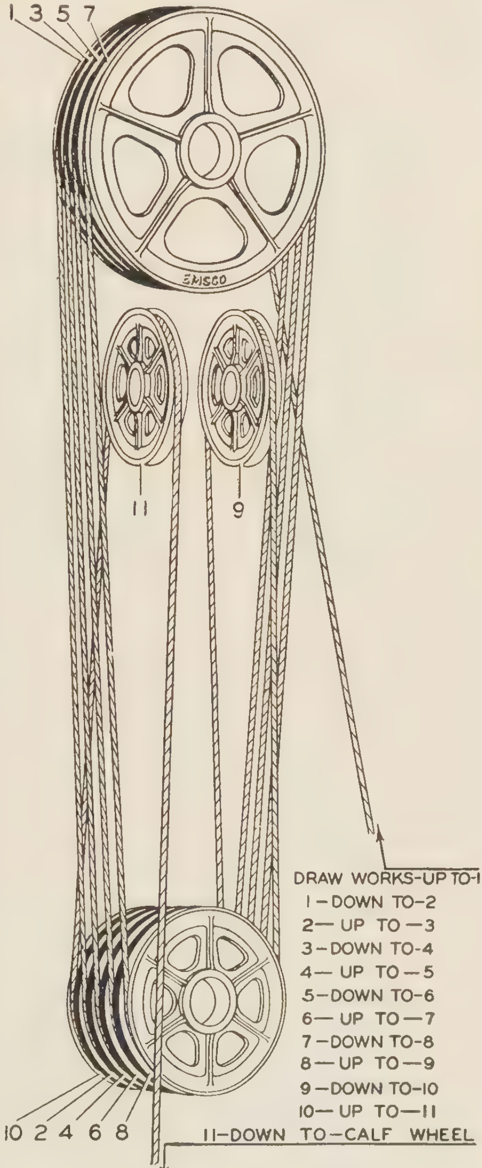


Fig. 121.—Four-sheave roller-bearing traveling block.

Casing Blocks or Hoisting Blocks.—The mechanical advantage necessary in handling a long string of heavy casing is secured through the use of a hoisting block containing from one to four sheaves, the calf or casing line being threaded between these and two or more sheaves at the derrick crown. The sheaves range in diameter from 10 to 26 in. and are sup-

ported by a heavy metal frame from 18 to 48 in. long, consisting of plates separating the sheaves and spaced apart by cylindrical spools, held together by three bolts, one of which, equipped with a loose bushing, serves as a shaft for the sheaves to turn on (see Fig. 121). A bail or link at both top and bottom provides a means of attaching ropes or hooks. Casing blocks should have a low center of gravity so that they do not turn over when the load is applied.

The mechanical advantage secured will depend upon the number of lines used and the method of stringing. The power applied at the calf-wheel drum will be multiplied as many times as there are lines strung between the hoisting block and the derrick crown, and the hoisting speed will be correspondingly diminished. Usually the end of the casing line or "dead line" will be attached to the top bail of the casing block, though in the case of the combination rig the other end may be attached to the draw-works hoisting drum. Figure 122 illustrates the usual manner of stringing a double-deck crown block and five-sheave casing block with eleven lines. If fewer lines are desired, one or more of the pulleys may be left unstrung.

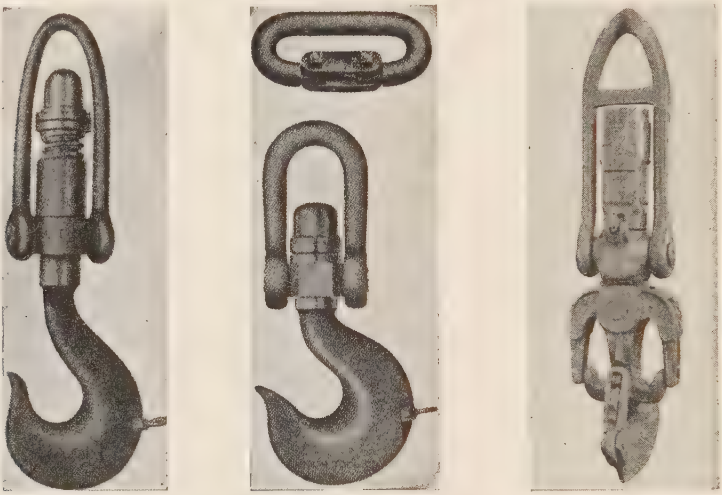


(*Emsco Derrick and Equipment Co.*)

FIG. 122.—Illustrating manner of stringing five-sheave traveling block.

Casing Hooks and Links.—The elevators are suspended from the lower bail of the hoisting block by a massive hook and a heavy split link or C-hook (see Fig. 123). The larger sizes of casing hooks weigh as much as 500 lb. The hook must

be free to turn in its supporting trunnion so that the casing can be rotated while suspended on the elevators without twisting the lines above the hoisting block. The bearing between the hook stem and the trunnion is often equipped with cone or ball bearings to eliminate friction, and in one type a spring is inserted to avoid the



A B C

FIG. 123.—Types of casing hooks.

A, "wiggle spring" hook; *B*, cone-bearing hook with strapped C-link; *C*, Byron-Jackson triple-suspension safety hook supporting both elevators and rotary swivel.

destructive jerk that otherwise results from sudden application of the power in lifting a column of casing. A clevis is sometimes attached to the edge of the hook for connecting a small control rope. The hook illustrated in Fig. 123*C* is designed to support both the elevators and rotary swivel.

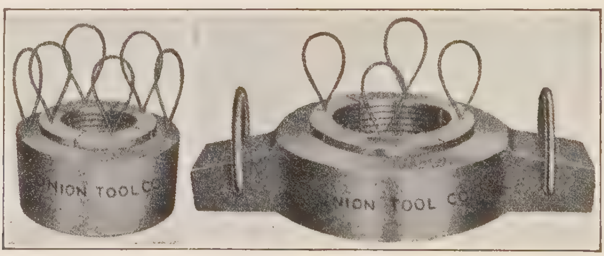


FIG. 124.—Casing spider with bushing and extra liner and slips.

Casing Spiders or Wedge Blocks.—In handling casing in the well a means must be provided for suspending a column of casing from the surface in such a manner that the open end of the casing is left free for drilling, bailing or other operations. For this purpose, a casing spider is used. This consists of a heavy forged steel ring with a conical hole

through its center (that is, larger at the top than at the bottom) and two projecting lugs at opposite points on the circumference (see Fig. 124). The hole through the ring is large enough to admit the largest sizes of casing, and conical steel liners are provided to adapt it to use with smaller sizes of pipe. Curved steel wedges, called "slips"—usually three or four in number—fit into the conical opening of the spider or liner in such a manner that when in position they form a cylindrical opening just large enough to admit the pipe. The inner edges of the slips are machined with horizontal serrated grooves. With the pipe suspended through the spider, the slips are dropped into position, and, as the pipe is slowly lowered, the slips slide down on their conical supports and are thus forced in against the pipe until the latter is gripped securely. The greater the weight of the column of casing, the more securely it is held. To remove the casing from the spider, it is only necessary to lift the casing slightly and withdraw the slips. Wire-rope loops are provided on the ends of the slips so that they may be readily placed in position or withdrawn without danger to the operator. The spider may rest either on the derrick floor or on timber supports in the bottom of the cellar; or it may be supported on cables or rods passing through links attached to the lugs. The weight of a casing spider ranges from 475 to nearly 2,000 lb., depending upon the maximum size of pipe for which it is designed.

Casing Tongs.—For turning the pipe in coupling and uncoupling screwed joints, pipe tongs of special design are provided. There are two general types: (1) the hinged-jaw type, and (2) the chain tong. The former are generally preferred for heavy service because of their positive grip, quick release and ease of application. A number of representative forms are illustrated in Fig. 125. Because of the heavy duty imposed upon them, casing tongs are necessarily large and heavy, the larger sizes weighing as much as 450 lb. Because of their great weight, it is necessary to suspend them in a horizontal position from a derrick crane or from a balanced beam in the derrick. The jaws of casing tongs are often equipped with bushings which adapt the same tongs to various sizes of pipe. Some models are reversible so that the pipe may be either screwed or unscrewed from one position of the tongs, that is, without turning the tongs over. This is accomplished by merely changing a metal pin controlling the leverage from one hole to another in the jaws.

Casing Wagons.—Before it is placed in the well, casing is usually stacked on the casing rack at one side of the derrick, and, as it is needed, it must be brought into the derrick and turned on end with the aid of the elevators. To aid in supporting and transporting the casing while it is in the horizontal position, two-wheeled casing wagons are provided, one to be placed at each end of the joint of pipe. One of these is equipped with a V-shaped support in which the front end of the pipe rests, and the other has a projecting hook which enters the rear end and, by depressing

the handle, lifts the pipe from the floor. The wheels and carriages are made entirely of steel, with pipe handles. Wooden or steel "dollies" consisting of a solid roller mounted under a small supporting carriage are preferred by some drillers in transporting casing and drill stem from the casing rack into the derrick.

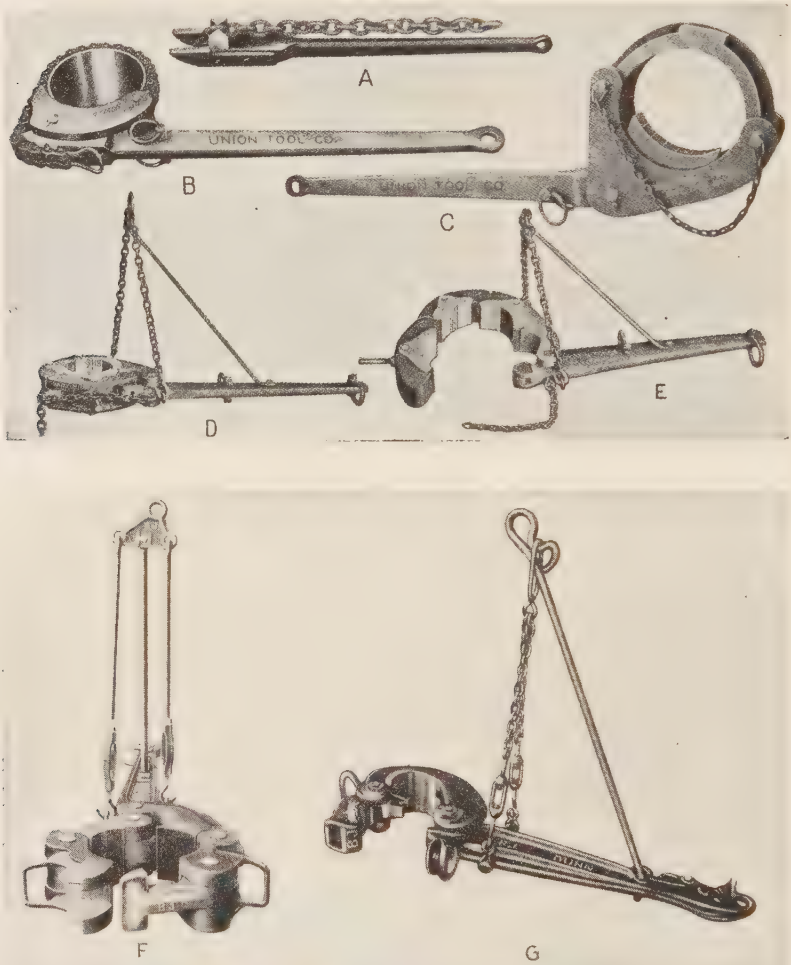


FIG. 125.—Types of casing tongs.
A, Kellerman chain tongs; *B*, Hardison tongs; *C*, Maddren tongs; *D*, Griffin tongs closed and *E*, open; *F*, Byron-Jackson Wilson type tongs and *G*, Dunn tongs.

Casing Adapters, Shoe Guides and Floating Plugs.—When a string of casing in a well does not extend to the surface and a smaller string of pipe or tools must be lowered through it, there is danger of the tools or smaller casings "hanging up" on the upper end of the column. To avoid this, it is customary to place a casing adapter on the top of the column of

pipe in the well, the adapter being beveled to guide the smaller string or tool through the opening (see Fig. 126*C*). Instead of this, or in addition to this, the shoe on the smaller string of pipe may be equipped with a shoe guide which serves the same purpose (see Fig. 126*B*).

In lowering a long string of casing into a well filled with water or mud, considerable strain may be taken off the elevators, spider and hoisting block if the lower end of the column be closed with a floating plug. In fact, if water be excluded from the casing, the buoyant force exerted is sufficient to float the column except in the case of the heaviest grades of

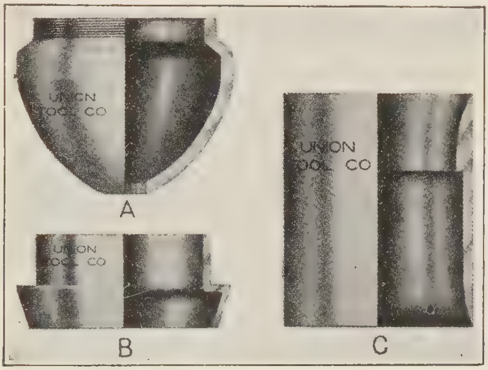


FIG. 126.—Floating plug (*A*), shoe guide (*B*) and casing adapter (*C*).

pipe. Often, however, the well will not be full of fluid and the floating plug takes care of only a part of the total weight. The plug used is generally hemispherical in form and is screwed to the bottom of the column of casing (see Fig. 126*A*). Being made of cast iron, it is readily broken up with the drilling tools when the casing has been "landed."

Drive Clamps and Heads.—When it becomes necessary to drive casing into a well, the cable drilling tools are generally used to provide the necessary impact. The tools are lowered into the well until the wrench square on the top of the drill stem is slightly above the top of the casing column. A pair of heavy clamps, with a square opening through them and held together by two bolts, is then clamped securely to the wrench square; the bull-wheel brake is clamped, a spudding shoe is placed on the drilling cable and a jerk line is connected from the spudding shoe to the wrist pin on the crank (see Fig. 127). The clamps placed on the stem are of such size that they do not pass through the open end of the casing. With the tools operated as in spudding (see page 169), the full weight of the string of tools is allowed to fall on the top of the column of casing with each stroke, the drive clamps striking on a "drive head," which has been previously screwed into the top coupling or on the top of the column of casing. Some types of drive heads are without threads and merely rest on the top of the column of casing. Typical drive clamps and heads are illustrated in Fig. 128.

Casing Jacks.—In freeing partially frozen casing, or in pulling casing from a well about to be abandoned, a powerful lifting force is often necessary. The force of the engine, even as multiplied by the calf wheel and hoisting block, is often inadequate, and recourse is had to the use of casing jacks. These are of two types: (1) screw jacks, and (2) hydraulic jacks. With the principle of the screw and the hydraulic jack it is assumed the reader is familiar. The latter are the more powerful, some

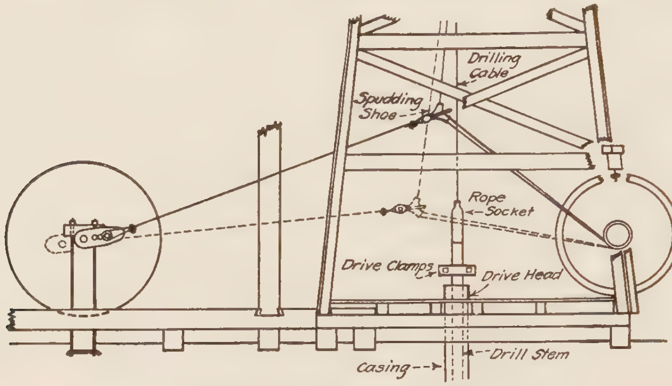


Fig. 127.—Illustrating method of driving casing.

of those designed for oil-well service being capable of lifting a load of 250 tons. In either case the jacks are applied through the aid of a casing spider which grips the pipe, two jacks being used, one under each lug on either side of the spider (see Fig. 129).

In placing stovepipe in a well, instead of driving it, it is sometimes preferable to use the pressure of a casing jack in forcing the casing down. For this purpose, a stovepipe "push head" is placed on the top of the

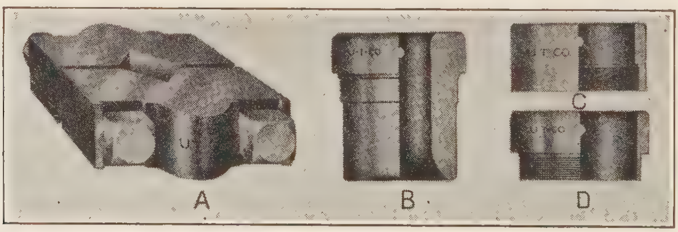


Fig. 128.—Drive clamps and heads.
A, clamps; *B*, drop head; *C* and *D*, screw heads.

column and the jack applied, rigged to push against anchor clamps bolted securely to the derrick foundations.

Casing Testers.—When a string of pipe has been used to exclude water from a well, it is sometimes necessary to find the location of a leak admitting water. For this purpose, a swab casing tester is used. This consists of a small cylindrical receptacle closed at the lower end, with a leather disk of such a diameter as will fit snugly inside of the casing

fastened around the top. A small bail permits of supporting the device on the sand line. Lowered to successively greater depths, occasionally withdrawing it to the surface to note whether or not water has accumulated in the tube, the leak is soon located and the necessary steps taken for its repair.

CASING INSTALLATIONS

Design of a Casing Installation.—The selection of sizes and weights of pipe to be used in casing a well, determination of the position of water shut-offs and the depth to which each string of pipe will be carried, should in so far as is possible be worked out in advance of actual drilling opera-

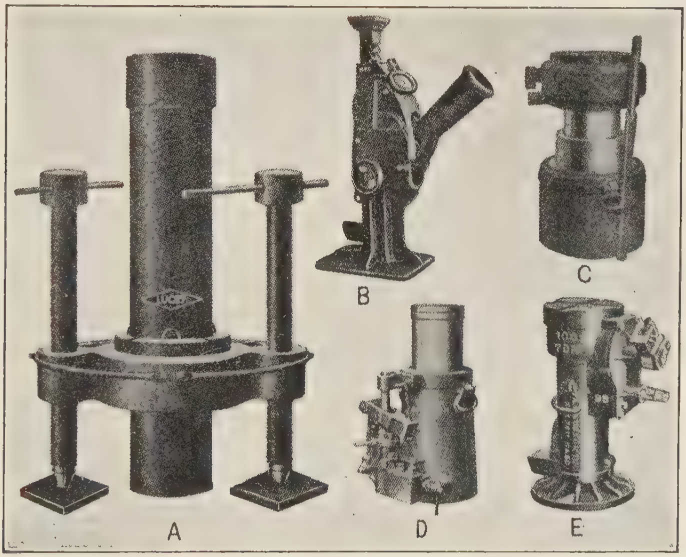


Fig. 129.—Types of jacks.
A, screw jacks lifting casing; *B*, lever type of jack; *C*, *D* and *E*, types of hydraulic jacks.

tions. If the well is a wildcat well and the depth of the producing horizon and character of the formations to be penetrated are uncertain, it will be impossible to plan the casing installation definitely in advance, that is, changes in size of casing, determination of the location of water shut-offs, etc., must be made from time to time as the work proceeds. But in a partially developed territory where the conditions to be met are approximately known, it should be possible, barring accidents, to select definitely all of the casing in advance and carry out its installation according to prearranged schedule.

In the latter case, the operator must first determine how many strings of pipe or how many changes in diameter will be necessary to reach the desired depth. This depends upon the depth of the producing horizon, the nature of the formations to be penetrated and the number of water

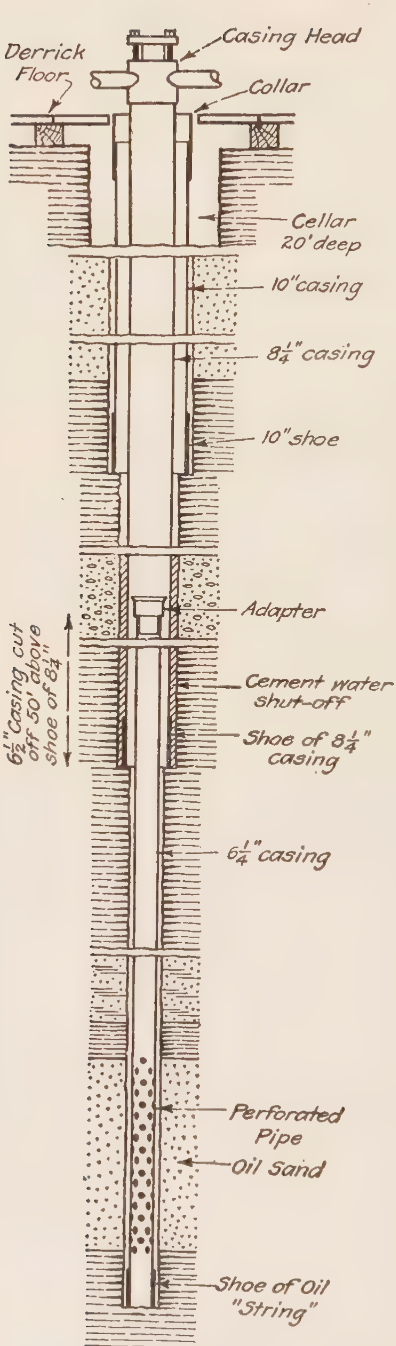


FIG. 130.—Illustrating manner of casing a well with three "strings" of pipe.

shut-offs necessary. Each water shut-off requires a change in the size of casing. The method of drilling used and the depth to which it is possible to carry a string of pipe in the given territory must also be taken into account. With the rotary equipment much greater freedom in selection of lengths of individual strings is possible than when the cable tools are used, because the casing is relatively free in the hole and there is less probability of accidental or unforeseen developments which prevent the carrying out of a prearranged program.

Having determined the necessary number of strings, the next consideration will be the size of drill with which it is desired to finish the well. This depends upon the nature of the oil-producing material, the productivity of wells in the region, the character of the oil and whether or not water or high-pressure gas is associated with it. There must be adequate clearance in the bottom of the well to accommodate a pump of the size necessary to handle the production expected. There must be, in addition, a moderate amount of space about the pump and well tubing in which oil may accumulate. In some districts an effort is made to complete wells with a minimum diameter of 6¼ in., which provides adequate clearance and oil space for the operation of a 3-in. plunger pump, a size of pump commonly used. Many wells are finished with a smaller diameter than this, but it seems reasonable to expect that production is not so efficiently obtained from them. It will be shown in a later

chapter that the flow of oil from a saturated sand increases with the area of wall surface exposed in the well, which gives the advantage to the well of larger diameter, from the economic point of view as well as from practical operating considerations.

Having determined upon the diameter with which the well is to be finished, and the necessary number of changes in size of the casing, it is a simple matter with the aid of the tables giving casing sizes, and bearing in mind that each string must pass freely through the previous string, to determine the minimum sizes of the respective strings and the initial diameter of the well. The A.P.I. series of standard casings is so designed that each size telescopes within the preceding size with a uniform clearance of about 3/8 in. all around between the inside wall of the outer string and the outside diameter of the coupling on the inside string. This clearance, it will be understood, varies to some extent, depending upon the thickness of walls of the outer string. Table XXXII presents several typical combinations of casing sizes used by operators in different American fields. Figure 130 illustrates a typical casing installation in which three strings of casing are used.

The hole drilled must be amply large to receive the size of casing to be used, with sufficient excess diameter to allow for occasional deflection of the axis and inequalities of bore. When drilling in soft or moderately hard formations, most operators believe that it is cheaper to drill the holes amply large rather than incur the additional expense of reaming tight places. For example, in certain California fields it is customary to drill a 19-in. hole for 13 3/8-in. casing; a 12 1/4-in. hole for 9 5/8-in. casing; and an 8 1/4- or 8 1/2-in. hole for 6 5/8-in. casing.

In approaching the design of a casing installation, it must be realized that a column of casing may fail to meet its requirements in a variety of ways. It may fail by tension under its own dead weight when not supported at the lower end or by wall friction. Failure in this way is possible only in the case of a very long column of pipe. Failure may result through collapse under external pressure due to the hydrostatic head of water or mud accumulated outside of the pipe when the lower end has been sealed in an impervious formation and the interior of the pipe is dry. Collapse of casing may also occur as a result of earth pressure. A column of casing may fail by bursting under excessive internal pressure. This is unusual, but is a possible cause of failure in the deeper territory where very high gas pressures must be contended with. If a column of pipe rests on the bottom of the well, or is frozen against the walls at some point, and there are cavities about it above the point of support, it may fail by column action due to the weight of the unsupported pipe above. Bending of casing due to this cause, it is thought, may be rather common. A column of casing may fail under lateral pressure due to bending stress. This is possible only where caving or shifting formations form

Table XXXII.—Typical Casing Programs in Various American Oil Fields

Long Beach Field, Calif.

Program 1		Program 2	
18 in. Stovepipe.	800 ft.	20 in. Stovepipe...	600 ft.
11¾ in., 54 lb., Grade C...	4,000 ft.	13⅜ in., 61 lb., Grade C....	3,000 ft.
8⅝ in., 36 lb., Grade C...	6,000 ft.	9 in., 40 lb., Grade C....	5,400 ft.
5¾ in., 22.5 lb., Grade C...	7,500 ft.	6⅝ in., 26 lb., Grade C....	6,600 ft.

Santa Fe Springs Field, Calif.

Program 1		Program 2	
18⅝ in., 84.5 lb., Grade C...	1,500 ft.	20 in. Stovepipe...	800 ft.
13⅜ in., 68 lb., Grade D..	4,150 ft.	13⅜ in., 68 lb., Grade C....	4,300 ft.
9 in., 45 lb., Grade D..	6,300 ft.	9 in., 45 lb., Grade D....	6,300 ft.
6⅝ in., 28 lb., Grade D..	7,350 ft.	6⅝ in., 28 lb., Grade D....	7,900 ft.
4¾ in., 16 lb., Grade C liner....	500 ft.	4¾ in., 16 lb., Grade C liner......	300 ft.

Kettleman Hills Field, Calif.

Program 1		Program 2	
18⅝ in., 84.5 lb., Grade C...	1,000 ft.	20 in., 90 lb., Grade C..	1,600 ft.
11¾ in., 60 lb., Grade C...	5,000 ft.	13⅜ in., 68 lb., Grade C..	5,300 ft.
8⅝ in., 43 lb., Grade D..	6,200 ft.	9⅝ in., 53.6 lb., Grade D..	6,300 ft.
5¾ in., 22.5 lb., Grade D..	7,500 ft.	7 in., 30 lb., Grade D..	7,000 ft.
		4¾ in., 16 lb., Grade D..	(Future)

Oklahoma City Field, Okla.

Program 1		Program 2	
9 in., 40 lb., Grade C....	5,500 ft.	20 in., 104 lb. Stovepipe..	250 ft.
6⅝ in., 26 lb., Grade C....	6,400 ft.	13⅜ in., 68 lb., Grade C...	2,100 ft.
4¾ in., 16 lb., Grade C.	(emergency)	9 in., 40 lb., Grade C...	5,500 ft.
		6⅝ in., 24 lb., Grade C...	6,300 ft.

Seminole Field, Okla.		Gulf Coast Exploration	
8⅝ in., 32 lb., Grade C....	4,000 ft.	13⅜ in., 61 lb., Grade D....	2,500 ft.
7 in., 24 lb., Grade C....	4,200 ft.	9⅝ in., 40 lb., Grade D....	6,000 ft.
$5\frac{3}{16}$ in., 17 lb., Grade C.	(emergency)	7 in., 28 lb., Grade D....	8,000 ft.
		5 in., 18 lb., Grade D.	(emergency)

Hobbs Field, N. Mex.		Big Lake Field, Tex.	
13⅜ in....................	(surface)	20 in., 90 lb., Grade C....	85 ft.
9⅝ in., 40 lb., Grade C....	2,800 ft.	13⅜ in., 61 lb., Grade D....	3,100 ft.
7 in., 24 lb., Grade C....	3,900 ft.	9⅝ in., 40 lb., Grade D....	5,800 ft.
5 in., 15 lb., Grade C.	(emergency)	7 in., 30 lb., Grade D.....	8,000 ft.

cavities of considerable size, while the pipe is supported against the walls of the well both above and below. If excessive earth pressure is developed and the pipe is rigidly supported opposite the point at which pressure is applied, it may be crushed. This however is really a form of collapse, which has already been mentioned. Casing may also fail by stripping of the threads or pulling apart at the joints—a form of failure particularly likely to occur if the pipe is also subjected to bending. Stresses of con-

siderable magnitude may be developed in a column of casing, due to expansion and contraction as a result of temperature changes. Such stress is developed only if the casing is held rigidly at top and bottom and at all points between, so that it cannot bend or expand longitudinally. Casing may fail in service through any one of these causes of stress, acting either singly or in combination. It is possible to estimate the stresses developed under different conditions with approximate accuracy and, to some extent, to design casing installations to withstand them.

The safe working stress in casing depends upon the character of the material of which it is made. Table XXX gives values for tensile strength and yield point of wrought iron and the several grades of steel of which oil-well casings are manufactured. The yield point is the property that is really most important, in that it should not be exceeded under working conditions. The yield point is usually about three-fifths of the tensile strength, and it is customary in casing design to allow a safety factor of two in terms of the tensile strength, that is, working loads are not permitted to exceed half of the tensile strength.

Tensile Stress Developed in Casing Due to Its Weight When Suspended from Its Upper End while Hanging Free.—When pipe is suspended from its upper end and is hanging free in the well without appreciable wall friction, we may compute the maximum stress developed in the pipe near its upper end with the aid of the formula

$$S = 12VL.$$

Here S is the stress in pounds per square inch, V is the density of steel in pounds per cubic inch (0.2833) and L is the length in feet. If we have a column of steel pipe 6,000 ft. long, hanging free in a well while supported only at its upper end, the maximum tensile stress developed will be

$$S = 12 \times 0.2833 \times 6{,}000 = 20{,}397.6 \text{ lb. per square inch.}$$

Or, if we wish to compute the maximum length of pipe that can be so suspended without exceeding the yield point of, say, grade A seamless casing, we have

$$30{,}000 = 12 \times 0.2833 \times L$$

or

$$L = 8{,}825 \text{ ft.}$$

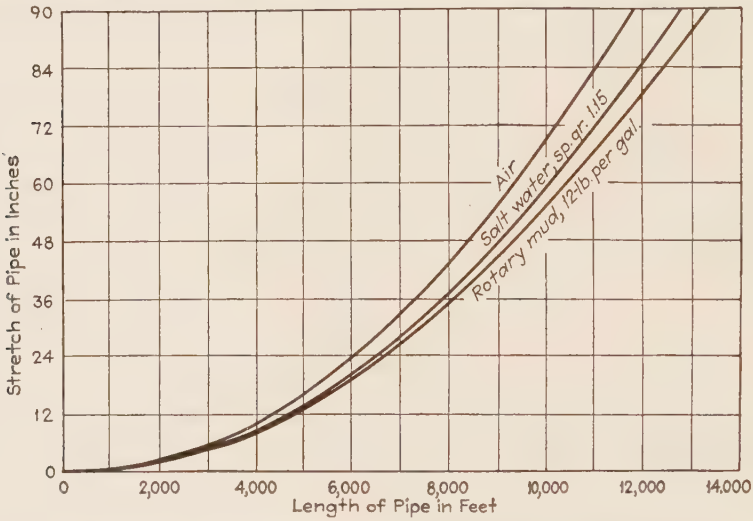
It is apparent that even with average strength casing, we are not likely to develop excessive tensional stresses due to dead weight of the pipe in wells of the depth that are being drilled today; nor does it seem likely that we will be drilling in the near future to depths at which dead-weight stress, acting alone, will be sufficient to cause failure of casing. If however, we wish to keep the working stress within 50 per cent of the yield point, which would be good engineering practice, we should select the stronger grades of steel where strings in excess of 4,500 ft. in length are to be set.

Strength of Screw Joints in Tension.—With the aid of the formula given in the preceding paragraph, the length at which the pipe will fail may be computed if the joints are as strong as the pipe itself. The ordinary type of threaded joint may fail by rupture at the base of the threads, under direct tension or by shearing of the threads. Screw joints may also fail by lateral contraction of the pipe and expansion of the coupling under tensional strain. This, combined with shearing stress, may result in the joint pulling out. Though the shearing strength of steel is only 75

per cent of the tensile strength, it is only a matter of making the joint long enough to offset any fundamental weakness due to low shearing strength. The pull-out strength of a collared joint is a function of the yield point of the metal, the length of thread engaged, the thickness of metal in the threaded portion of the pipe and the friction angle of thread contact relative to the axis of the pipe. For A.P.I. standard casings, using collared joints with 60-deg. V-threads on a ⅜-in. taper,

$$P = \frac{6.28\,abf}{0.206 + \frac{a}{d}}.$$

Here P is the total pull in pounds, necessary to separate the joint; a is the length of engaged threaded portion of the pipe in inches; b is the average thickness of metal in engaged threaded portion in inches; f is the yield point of the metal in pounds per



(*From Spang, Chalfant & Co.'s data sheets.*)

Fig. 131.—Graphs showing elongation of steel casing, tubing or drill pipe under the influence of its own weight while suspended freely in various fluid media.

square inch; and d is the average diameter of the pipe, measured to the center of the metal in the engaged threaded portion, in inches. With the aid of this formula we may compute the pull-out strengths for different sizes and weights of casing and collars (see Table XXXIII). Computations show that ultimate failure of casing joints will occur at approximately the yield point of the metal for the pipe cross section.

Elongation of Casing in Tension.—Occasionally it is necessary to compute the elongation of a suspended column of casing under tension developed by its own weight; or, in pulling on frozen casing, where the pipe is held fast at some point in the well, it may be desired to compute the elongation of the pipe when a certain lifting force is applied. For this purpose we may make use of the formula

$$e = \frac{72VL^2}{E}.$$

Here e is the elongation in inches, V is the weight per cubic inch (0.2833 lb. for steel), L is the length in feet and E is the modulus of elasticity (30,000,000 for steel). Figure 131 shows graphically the normal elongation of casing, tubing or drill pipe when suspended freely in air, water or drilling fluid.

Table XXXIII.—Tensile Strengths of A.P.I. Casings*

Casing outside diameter, in.	Weight per foot, lb.	Thickness, in.	Area of metal		Yield load, body of pipe		Ultimate load, root of first perfect thread		Pull-out strength A.P.I. couplings (Thomas formula)	
			Body of pipe, sq. in.	Root of first perfect thread, sq. in.	Unit stress, 45,000 lb.	Unit stress, 57,000 lb.	Unit stress, 75,000 lb.	Unit stress, 95,000 lb.	Yield point, 45,000 lb.	Yield point, 57,000 lb.
4¾	16.0	.334	4.634	3.47	208,000	264,000	260,000	330,000	231,000	293,000
5¾	14.0	.230	3.990	2.57	180,000	227,000	193,000	244,000	180,000	229,000
5¾	17.0	.280	4.800	3.28	216,000	274,000	246,000	312,000	232,000	293,000
5¾	19.5	.330	5.610	4.19	252,000	320,000	314,000	398,000	282,000	358,000
5¾	22.5	.380	6.410	4.98	288,000	366,000	374,000	473,000	332,000	420,000
6⅝	20.0	.288	5.734	4.07	258,000	327.000	305,000	386,000	264,000	334,000
6⅝	24.0	.352	6.937	5.29	312,000	395,000	397,000	503,000	336,000	425,000
6⅝	26.0	.385	7.547	5.39	340,000	430,000	404,000	512,000	372,000	472,000
6⅝	28.0	.417	8.133	6.49	366,000	463,000	487,000	617,000	405,000	513,000
7	20.0	.272	5.749	4.03	259,000	328,000	302,000	383,000	256,000	324,000
7	22.0	.301	6.335	4.57	285,000	361,000	343,000	434,000	290,000	367,000
7	24.0	.332	6.955	5.23	313,000	396,000	392,000	497,000	325,000	412,000
7	26.0	.362	7.549	5.82	340,000	430,000	437,000	553,000	360,000	456,000
7	28.0	.393	8.157	6.43	365,000	463,000	482,000	611,000	396,000	502,000
7	30.0	.423	8.740	7.02	393,000	498,000	527,000	667,000	430,000	545,000
8⅛	28.0	.320	7.800	5.82	351,000	445,000	437,000	553,000	364,000	461,000
8⅛	32.0	.370	9.070	7.00	408,000	517,000	525,000	665,000	364,000	461,000
8⅛	35.5	.420	10.290	8.22	463,000	587,000	617,000	781,000	501,000	635,000
8⅛	39.5	.470	11.360	9.28	511,000	648,000	696,000	882,000	501,000	635,000
8⅝	28.0	.304	7.947	6.82	358,000	453,000	512,000	648,000	349,000	442,000
8⅝	32.0	.352	9.149	7.00	412,000	522,000	525,000	665,000	413,000	524,000
8⅝	36.0	.400	10.340	8.18	465,000	589,000	614,000	777,000	479,000	606,000
8⅝	38.0	.425	10.950	8.80	493,000	624,000	660,000	836,000	520,000	658,000
8⅝	43.0	.487	12.450	10.31	560,000	710,000	723,000	979,000	608,000	762,000
9	34.0	.355	9.641	6.84	434,000	549,000	513,000	650,000	412,000	522,000
9	38.0	.402	10.860	8.14	489,000	619,000	611,000	773,000	478,000	605,000
9	40.0	.425	11.450	8.65	515,000	653,000	649,000	822,000	510,000	650,000
9	45.0	.484	12.950	10.16	583,000	738,000	762,000	965,000	593,000	751,000
9	54.0	.594	15.700	12.90	707,000	895,000	968,000	1,225,000	745,000	943,000
9⅝	43.8	.435	11.700	9.57	527,000	667,000	718,000	909,000	510,000	647,000
9⅝	47.2	.472	13.590	10.58	612,000	775,000	794,000	1,005,000	601,000	762,000
9⅝	53.6	.545	15.460	12.55	696,000	881,000	941,000	1,192,000	708,000	897,000
9⅝	57.4	.587	16.660	13.69	750,000	950,000	1,027,000	1,301,000	767,000	972,000
10¾	40.5	.350	11.440	7.93	515,000	652,000	595,000	753,000	464,000	537,000
10¾	45.5	.400	13.000	9.66	585,000	741,000	725,000	918,000	555,000	703,000
10¾	51.0	.450	14.550	11.23	655,000	829,000	842,000	1,067,000	639,000	809,000
10¾	55.5	.495	15.940	12.60	717,000	909,000	945,000	1,197,000	707,000	896,000
11¾	47.0	.375	13.400	9.74	603,000	764,000	731,000	925,000	515,000	653,000
11¾	54.0	.435	15.440	11.78	695,000	880,000	884,000	1,119,000	615,000	779,000
11¾	60.0	.489	17.300	13.66	779,000	986,000	1,025,000	1,298,000	703,000	890,000
13⅜	48.0	.330	13.660	9.34	615,000	779,000	701,000	887,000	512,000	648,000
13⅜	54.5	.380	15.620	11.31	703,000	890,000	848,000	1,074,000	611,000	774,000
13⅜	61.0	.430	17.580	13.27	791,000	1,002,000	995,000	1,261,000	710,000	899,000
13⅜	68.0	.480	19.550	15.23	880,000	1,114,000	1,144,000	1,449,000	806,000	1,020,000

* After C. J. Coberly in A.P.I. *Bull.* 204, January, 1930.

Buoyant Effect of the Well Fluid.—It should be pointed out that the foregoing formulas do not take into account the buoyant effect of fluid in the well, which operates to reduce the effective density of the steel. The weight of steel casing in water is 0.2455 lb. per cubic inch or 86.8 per cent of the value in air. In mud, weighing 90 lb. per cubic foot, its weight is 0.230 lb. per cubic inch or 81.1 per cent of its weight in air.

Collapse of Casing.—Collapse of casing may be caused by external pressure having its origin in hydrostatic head brought to bear on the pipe, or in earth pressure developed by caving or shifting walls, or sudden "heaving" of unconsolidated sand

into the well from oil or gas horizons. Where casing is set to exclude top waters, fluid accumulating outside the pipe may reach elevations of many hundreds of feet above the casing shoe or at times even to the surface. The hydrostatic head so developed, tending to collapse the casing, will vary with the density of the fluid: thus, water develops a pressure of 0.433 lb. per foot of depth; saline ground water containing 33,800 parts of dissolved salt per million develops a pressure of 0.444 lb. per foot; drilling fluid weighing 10 lb. per gallon, 0.520 lb. per foot; and 15 lb. drilling fluid, 0.780 lb. per foot. For average conditions, in making approximate computations, we may assume that the fluid has a density of 1.15 and that it develops a static pressure of 0.5 lb. per square inch per foot of depth. In conservative computations it is well to assume that fluid outside the pipe extends to the surface and that a collapsing pressure is developed on the casing equivalent to a fluid head of its full length. Reflection will show that this collapsing pressure may become a force of great magnitude, reaching as much as 3,000 lb. per square inch in a well 6,000 ft. deep.

The resistance offered by tubes to external pressure tending to cause collapse has been the subject of a number of investigations and several formulas have been developed that are useful in making computations of this character. When a tube resists uniform external pressure, the metal is subjected to compressive strain, the magnitude of which is a function of the pressure, the external diameter of the tube and a factor called the "slenderness ratio," which is the thickness of the wall of the tube divided by the external diameter (t/d). For thin-walled tubes the resistance to collapse is curiously found to be independent of the compressive strength of the material of which the pipe is constructed. Love's formula, applying only to thin-walled tubes, is as follows:

$$P = \frac{2E(t/d)^3}{1 - M^2}.$$

Here P is the pressure in pounds per square inch at the yield point; E is the modulus of elasticity of the material; t is the thickness of the tube in inches; d is the external diameter in inches; and M is Poisson's ratio of lateral to transverse deformation. The modulus of elasticity (E) is practically constant for all grades of steel, having an average value of 29,000,000. Poisson's ratio (M) has likewise a constant value for a given material, being approximately 0.3 for steel. It is apparent from this formula that increasing the tensile or compressive strength of the steel from which thin-walled pipe is made would have no effect on its resistance to collapse.

In the case of thick-walled tubes the elasticity of the metal is of less consequence, and the resistance offered against collapse is dependent chiefly upon the strength of the metal. Lamé's formula, governing this condition, is

$$P = 2U_c\left[\left(\frac{t}{d}\right) - \left(\frac{t}{d}\right)^2\right].$$

Here U_c is the ultimate compressive strength of the material, and the other symbols are the same as in Love's formula. In the case of thick-walled tubes, the formula shows that we may increase the resistance to collapse by selecting materials of greater compressive strength.

In order that we may know which to apply of the two formulas presented above, we must be able to define the limit separating thin-walled tubes from thick-walled tubes. In 1906 R. T. Stewart conducted a long series of experimental tests on the collapsing strength of steel tubes and by analyzing the data developed two formulas that have been the basis for most tables of collapsing pressure that have been published by the pipe manufacturing companies (see Table XXXIV). Stewart recognized the difference between the factors governing the performance of thin-walled and thick-walled tubes and assigned a value of 0.023 for the limiting value of t/d; that is, where

TABLE XXXIV.—COLLAPSING PRESSURES AND SETTING DEPTHS OF A.P.I. CASINGS*
(No factor of safety used)

Casing outside diameter, in.	Weight per foot, lb.	Thickness, in.	Ratio thickness to diameter $\frac{t}{d}$	Collapsing pressure, lb. per sq. in.			Setting-depth corresponding to collapsing pressure, ft.					
							Salt-water specific gravity, 1.027			Drilling mud, 10 lb. per gal.		
				Unit stress, 30,000 lb.	Unit stress, 45,000 lb.	Unit stress, 57,000 lb.	Unit stress, 30,000 lb.	Unit stress, 45,000 lb.	Unit stress, 57,000 lb.	Unit stress, 30,000 lb.	Unit stress, 45,000 lb.	Unit stress, 57,000 lb.
4¾	16.0	.334	.0703	4,110	5,880	7,310	9,250	13,240	16,640	7,900	11,300	14,050
5¾	14.0	.230	.0400	1,860	2,510	3,020	4,200	5,660	6,810	3,580	4,830	5,800
5¾	17.0	.280	.0487	2,410	3,480	4,260	5,410	7,830	9,580	4,630	6,680	8,170
5¾	19.5	.330	.0574	3,160	4,450	5,480	7,100	10,010	12,350	6,060	8,540	10,530
5¾	22.5	.380	.0660	3,790	5,400	6,690	8,540	12,160	15,060	7,280	10,380	12,850
6⅝	20.0	.288	.0435	2,120	2,900	3,520	4,780	6,520	7,930	4,080	5,560	6,760
6⅝	24.0	.352	.0532	2,840	3,980	4,890	6,400	8,960	11,020	5,460	7,640	9,400
6⅝	26.0	.385	.0582	3,219	3,560	5,600	7,240	10,220	12,610	6,180	8,710	10,760
6⅝	28.0	.417	.0629	3,560	5,060	6,260	8,030	11,400	14,080	6,850	9,720	12,010
7	20.0	.272	.0389	1,780	2,390	2,870	4,020	5,370	6,470	3,420	4,580	5,520
7	22.0	.301	.0430	2,060	2,840	3,460	4,640	6,410	7,780	3,960	5,470	6,640
7	24.0	.332	.0474	2,410	3,340	4,070	5,430	7,500	9,170	4,640	6,400	7,820
7	26.0	.362	.0518	2,740	3,820	4,690	6,170	8,610	10,560	5,260	7,340	9,010
7	28.0	.393	.0562	3,070	4,320	5,310	6,900	9,710	11,960	5,890	8,280	10,200
7	30.0	.423	.0605	3,390	4,790	5,920	7,620	10,790	13,330	6,400	9,200	11,370
8⅛	28.0	.320	.0394	1,820	2,440	2,930	4,100	5,500	6,670	3,500	4,690	5,650
8⅛	32.0	.370	.0456	2,280	3,130	3,820	5,130	7,060	8,590	4,380	6,020	7,330
8⅛	35.5	.420	.0517	2,730	3,810	4,680	6,160	8,580	10,530	5,250	7,320	8,980
8⅛	39.5	.470	.0579	3,190	4,500	5,500	7,190	10,140	12,500	6,130	8,650	10,660
8⅝	28.0	.304	.0353	1,520	1,990	2,360	3,410	4,470	5,320	2,910	3,820	4,540
8⅝	32.0	.352	.0408	1,920	2,600	3,140	4,330	5,850	7,070	3,690	4,980	6,030
8⅝	36.0	.400	.0464	2,340	3,220	3,930	5,260	7,250	8,840	4,490	6,180	7,540
8⅝	38.0	.425	.0493	2,560	3,540	4,340	5,750	7,980	9,760	4,910	6,800	8,340
8⅝	43.0	.487	.0565	3,090	4,350	5,360	6,960	9,790	12,050	5,930	8,350	10,280
9	34.0	.355	.0395	1,830	2,450	2,960	4,120	5,520	6,650	3,510	4,710	5,680
9	38.0	.402	.0047	2,210	3,030	3,690	4,980	6,830	8,310	4,250	5,820	7,090
9	40.0	.425	.0472	2,400	3,310	4,040	5,400	7,460	9,100	4,610	6,360	7,760
9	45.0	.483	.0536	2,870	4,020	4,950	6,470	9,060	11,130	5,520	7,720	9,500
9	54.0	.594	.0660	3,790	5,400	6,700	8,540	12,160	15,090	7,280	10,380	12,860
9⅝	43.8	.435	.0452	2,240	3,090	3,760	5,050	6,940	8,470	4,310	5,930	7,220
9⅝	47.2	.472	.0491	2,540	3,520	4,310	5,710	7,920	9,700	4,870	6,760	8,280
9⅝	53.6	.545	.0566	3,100	4,360	5,370	6,960	9,800	12,070	5,940	8,360	10,310
9⅝	57.4	.587	.0610	3,420	4,850	6,000	7,700	10,910	13,510	6,580	9,310	11,540
10¾	40.5	.350	.0325	1,310	1,670	1,970	2,940	3,760	4,440	2,510	3,210	3,790
10¾	45.5	.400	.0372	1,660	2,190	2,630	3,730	4,930	5,930	3,180	4,210	5,060
10¾	51.0	.450	.0419	2,000	2,720	3,300	4,510	6,120	7,420	3,850	5,220	6,340
10¾	55.5	.495	.0460	2,310	3,180	3,870	5,200	7,150	8,720	4,440	6,100	7,440

* Figures in this table on collapse have been computed by extending Thomas' formula.

TABLE XXXIV.—COLLAPSING PRESSURES AND SETTING DEPTHS OF A.P.I. CASINGS.*
(*Continued*)

Casing outside diameter, in.	Weight per foot, lb.	Thickness, in.	Ratio thickness to diameter $\frac{t}{d}$	Collapsing pressure, lb. per sq. in.			Setting-depth corresponding to collapsing pressure, ft. Salt-water specific gravity, 1.027			Setting-depth corresponding to collapsing pressure, ft. Drilling mud, 10 lb. per gal.		
				Unit stress, 30,000 lb.	Unit stress, 45,000 lb.	Unit stress, 57,000 lb.	Unit stress, 30,000 lb.	Unit stress, 45,000 lb.	Unit stress, 57,000 lb.	Unit stress, 30,000 lb.	Unit stress, 45,000 lb.	Unit stress, 57,000 lb.
11¾	47.0	.375	.0319	1,260	1,610	1,880	2,840	3,620	4,240	2,430	3,090	3,620
11¾	54.0	.435	.0370	1,640	2,170	2,600	3,700	4,890	5,860	3,150	4,180	5,000
11¾	60.0	.489	.0416	1,980	2,690	3,250	4,460	6,040	7,320	3,830	5,160	6,260
13⅜	48.0	.330	.0247	730	820	920	1,640	1,840	2,060	1,400	1,570	1,760
13⅜	54.5	.380	.0284	1,000	1,220	1,390	2,260	2,740	3,130	1,930	2,340	2,680
13⅜	61.0	.430	.0321	1,280	1,630	1,910	2,880	3,670	4,310	2,450	3,130	3,670
13⅜	68.0	.480	.0359	1,560	2,050	2,450	3,510	4,620	5,510	3,000	3,940	4,700
16	55.0	.3125	.0195	370	400	450	830	910	1,020	710	770	870
16	65.0	.3750	.0234	630	690	780	1,420	1,560	1,760	1,210	1,340	1,500
16	75.0	.4375	.0273	920	1,090	1,240	2,080	2,460	2,780	1,770	2,100	2,370
16	84.0	.4950	.0309	1,190	1,500	1,740	2,670	3,370	3,920	2,280	2,870	3,350
18⅝	78.0	.3850	.0207	440	480	540	990	1,080	1,220	840	920	1,040
18⅝	87.5	.4350	.0233	620	680	770	1,410	1,540	1,730	1,200	1,310	1,480
18⅝	96.5	.4850	.0260	820	950	1,070	1,850	2,140	2,400	1,580	1,830	2,050
21½	92.5	.3950	.0183	300	330	370	680	750	840	580	640	710
21½	103.0	.4450	.0207	440	480	540	990	1,080	1,220	840	920	1,040
21½	114.0	.4950	.0230	600	660	740	1,350	1,480	1,660	1,160	1,260	1,420
24½	100.5	.3750	.0153	180	190	220	400	430	490	340	370	420
24½	113.0	.4250	.0173	260	280	310	580	630	700	490	540	600

* Figures in this table on collapse have been computed by extending Thomas' formula.

the value of t/d is less than 0.023, Stewart found that the elastic formula controls, but where t/d is greater than 0.023, the strength formula holds. Stewart's equations, being empirical formulas, are somewhat easier to apply than those of Love and Lamé. They are as follows:*

For thin-walled tubes, t/d less than 0.023:

$$P = 50{,}210{,}000\left(\frac{t}{d}\right)^3.$$

For thick-walled tubes, t/d greater than 0.023:

$$P = 86{,}670\frac{t}{d} - 1{,}386.$$

* When P is greater than 581 lb. per square inch, the formula for thick-walled tubes should be used, while the thin-walled tube formula is employed when P is less than 581 lb.

These formulas apply only to Bessemer steel tubes or to pipe made of steel having properties approximating those of Bessemer steel. H. A. Thomas has developed formulas of the same form as those of Stewart, with the exception that the yield point of the steel is brought into the relation, thus making it possible to compute the collapsing strength of casing made from material of greater strength than Bessemer steel. Thomas's formulas are as follows:

For thick-walled tubes:

$$P = 2.476\frac{ft}{d} - 0.056f + 574.$$

For thin-walled tubes:

$$P = \frac{2.25\ (ft/d)^3}{(0.056f - 574)^2}.$$

In these formulas f is the yield point of the material, and the limiting value between thick- and thin-walled tubes is found to occur when $t/d = 0.034 - 348/f$. The limiting values of t/d for different grades of steel, as determined by this expression, are as follows:

A.P.I. grade	A.P.I. minimum yield point, lb. per sq. in.	Limiting value of t/d
Bessemer welded	30,000	.022
Seamless A	30,000	.022
Seamless B	40,000	.025
Seamless C	45,000	.026
Seamless D	57,000	.028

The ratio of t/d for A.P.I. standard casing sizes ranges from 0.028 to 0.070 for all sizes up to and including 13⅜ in.; hence for all casings of this group we must use Thomas's formula for thick-walled tubes. For sizes ranging from 16 to 24½ in. values of t/d range between 0.015 and 0.031, hence we use sometimes one and sometimes the other of the two formulas but generally the formula for thin-walled tubes.

Computations made with the aid of the Thomas formulas show that only the stronger grades of seamless steel are capable of resisting successfully the hydrostatic heads developed in deep wells now being drilled in some of our western and mid-continent American fields. For example, 8⅝-in. 43-lb. casing—the heaviest of the A.P.I. standards in this size—will collapse if cemented at a depth of 5,930 ft. assuming that Bessemer welded or seamless grade A pipe is used and that 10 lb. mud is the fluid outside the pipe. Seamless grade D casing, on the other hand, can be carried safely to a depth of 10,280 ft.; this, however, assumes that no safety factor is used. If we adopt a safety factor of two, which is appropriate for this class of work, we should use the strongest grade of seamless pipe whenever 8⅝-in. casing is set at depths of 5,000 ft. or more. Larger sizes of pipe are even less secure at great depths; for example, using a safety factor of two, with 10 lb. fluid in the well, we are able to carry the strongest and heaviest grade of 13⅜-in., 68-lb. casing to only 2,350 ft. without danger of collapse.

Hydrostatic head produces a tendency to collapse only when the fluid outside the casing stands at a higher level than that within. Some operators reduce the risk of

collapse by filling the space between strings with mud fluid. This brings all the collapsing stress to bear upon the inside string, which, being the smallest in diameter, is best able to support it. Owing to carelessness or lack of appreciation of the importance of proper design in casing installations, there are wells in which it would be unsafe to bail or pump the fluid level down to the level of the shoe of the water string without danger of collapse. High fluid levels, thus necessarily maintained, greatly reduce the ultimate recovery obtainable from the wells.

Strength of Casing in Column Loading.—When casing is set on bottom and is not supported at the upper end—as in the case of a liner that does not extend to the surface—there is under certain conditions possibility of failure through excessive column loading. If caving of the walls has left a cavity about the pipe so that it does not receive support from the walls, it must function as a column in supporting the weight of the pipe above. The stress developed will depend upon the nature of the footing provided at the lower end. If the pipe stands in loose formation at the bottom of the cavity, the load at failure, due to column action, is given by the expression:

$$P = \frac{\pi^2 EI}{L^2}.$$

In this equation P is the load in pounds, I is the moment of inertia, L is the length in inches and E is the modulus of elasticity of the material. Computations with this formula indicate that a 100-ft. unsupported length of 4¾-in., 16-lb. pipe would fail if the pipe were 145 ft. long. If the pipe is rigidly supported at its lower end, the load at failure is given by the expression

$$P = 2.05 \frac{\pi^2 EI}{L^2}.$$

It is apparent that a longer column of pipe can be sustained without wall support when the lower end is rigidly supported than when it is free to move. Computations indicate a safe length of 297 ft. of 4¾-in., 16-lb. pipe with an unsupported length of 100 ft. when the lower end is fixed.

The column strength of casing increases rapidly with increase in diameter and for a given diameter is approximately proportional to the weight. Computations based on the two formulas, given above, show that long unsupported liners in wells are likely to buckle. Columns of casing extending to the surface are commonly supported at their upper ends, so that they are maintained—at least partially—under tension. Column loading is therefore not a factor of importance in such cases; but where this practice is not followed, or where insufficient tension is taken and maintained at the well head, buckling may result wherever the walls fail to give adequate support.

Bending Stresses in Casing.—Bending stresses sufficient to cause distortion of casing may result in either of two ways. In a crooked hole the casing must, of course, adapt itself to changes in the direction of the bore, and where conditions are developed which cause caving or bulging of the wall of the well against the pipe important lateral stress may be developed. Though difficult of evaluation on any mathematical basis, these stresses are probably often responsible for deformation in casing, especially where the wells penetrate high-pressure unconsolidated formations. Where a well has been surveyed, and the deviation and direction of the axis from the vertical are known, it is possible to estimate the bending stress developed during insertion of the casing with the aid of the formula

$$S = \frac{CE}{12R}.$$

In this formula S is the unit stress developed, in pounds per square inch; C is the distance from the neutral axis to the outer fiber—in this case, one-half the outside diameter of the pipe—in inches; E is the modulus of elasticity of the material; and R is the radius of curvature in feet. If, as is usual, the survey data give deflection from the vertical in degrees instead of the radius of curvature, we may compute the latter by substituting in the following formula:

$$a = \frac{5{,}720}{R},$$

in which a is the angle from the vertical in degrees; and R is the radius of curvature in feet.

With large-diameter casing, the stress produced in running casing into a crooked hole may become an important contributing factor in casing failure. For example, if casing 9 in. in outside diameter is run into a hole in which there is a 5-deg. change in direction in 100 ft. of hole, the stress developed in the pipe will be nearly 10,000 lb. per square inch. If the deflection were 10.2 deg., the stress would be 20,000 lb. and a 15.3-deg. deflection would develop a stress in the casing of 30,000 lb. per square inch.

Stress in Casing Due to Temperature Change.—The stresses developed in casing due to temperature changes are not likely to be excessive, though in conjunction with other forces brought to bear they may be worthy of consideration. Stress due to temperature change is realized only when the ends of the pipe are fixed so that compensating changes in length may not occur. Tendency to contract, as a result of reduction in temperature, will then be resolved into tensional stress, but compressive strain developed by expansion will generally be relieved by bending or distortion. A temperature change of 100°F. produces a change in the length of a column of casing, of 0.78 in. per 100 ft. If the ends of the pipe are fixed so that the length cannot change, the stress developed may be computed with the aid of the formula

$$S = atE.$$

In this expression, S is the casing stress in pounds per square inch; a is the coefficient of expansion of the material (0.0000065 for steel); t is the temperature change in degrees Fahrenheit; and E is the modulus of elasticity of the material. Computation indicates a value of S for steel, of 195 lb. per square inch per degree Fahrenheit.

Stress Due to Internal Pressure in Casing.—During the early period of development in some very deep producing structures, casings and flow strings are occasionally subjected to high internal pressures tending to cause rupture of the pipe. Shut-in pressures as great as 2,500 lb. per square inch have been noted in some cases. When a tube is subjected to internal pressure, the forces operative tend to hold it in cylindrical form and the resultant forces produce tension around the circumference of the tube. If a safe working stress is exceeded, the pipe fails by splitting longitudinally. Barlow's formula, which may be used for computing this stress due to internal pressure, is as follows:

$$S = \frac{Pd}{2t}.$$

In this formula S is the unit stress in the metal, P the pressure in pounds per square inch. d the outside diameter of the tube in inches and t the thickness of the tube in inches.*

* Much of the material presented in the above section dealing with casing stresses has been adapted from a paper by C. J. Coberly, entitled, Analysis of Casing Stresses and California Casing Practice, A.P.I. *Bull.* 204, pp. 22–51, January, 1930.

Inserting Casing

In the case of a well drilled by rotary tools, no casing is inserted until the particular size of hole being drilled is completed. When the hole is drilled to its full depth, the casing will be lowered as rapidly as possible, and "landed" on bottom or cemented to exclude water, after which drilling is continued with a smaller sized bit. With cable tools a somewhat different procedure is followed in that the casing is often installed joint by joint as the hole is deepened. This is not necessarily the case when drilling in hard rock where the walls will "stand up" for depths of hundreds of feet without casing. In softer rocks which have a tendency to cave, however, the casing must be lowered progressively as the well is deepened, keeping the casing shoe but a short distance above the bit. When the cable tools are used, it is a poor plan to let the rope socket or jars extend below the casing shoe, because of the danger of the tools falling to one side and getting the upper end caught behind the shoe. However, the cable tools cut a larger hole if permitted to drill 20 to 30 ft. ahead of the shoe, and for this reason the casing is usually suspended at about this distance off bottom unless there is danger to the casing or the tools by so doing.

Inserting Conductor Casing.—The first column of pipe placed in the well is the "conductor pipe," designed primarily to exclude soft and poorly consolidated surface formations which often show a tendency to cave. As this string is seldom carried to depths of more than a thousand feet—often much less—it may be of light construction. To avoid wall friction and loss of working diameter, riveted or welded "stovepipe" or special forms of thin-walled, inserted-joint steel casing, also designed for welding, are generally used. The manner of inserting such casing will depend upon its construction and the method of drilling in use.

When the well is drilled with cable tools, it is left uncased while spudding is in progress or until the walls show a tendency to cave. The tools are then withdrawn, and if riveted stovepipe is to be used, the "starter joint," which carries a light steel shoe riveted to its lower end, is started into the well. As it is lowered, additional sections are attached, picking, riveting or spot welding them together so that the joints may not pull apart under tension. The column of pipe in the well is meanwhile supported by a pair of wooden clamps or friction blocks, securely bolted around the pipe and supported either on timbers placed on the derrick floor or by wire slings from the casing hook. The column is lowered or raised with the aid of power applied through the calf wheel. A pair of drive clamps on the drill stem may be used to drive the new joints lightly so that they telescope to the desired degree.

Only a few hundred feet of "picked" stovepipe can be lowered into an open hole if it receives no support from the walls without danger of the joints pulling apart. Usually, however, the pipe makes contact here and there with the walls so that wall friction may be counted upon to aid in holding the string together. Indeed, the friction developed is often so great that light driving is necessary to force the pipe into the well. In cases of extreme friction, hydraulic jacks may be called into service to force the column down. If the conductor string is a long one, or of large diameter and unusually heavy, a float valve may be placed in the column near the lower end, to carry part of the weight and give added insurance that it will not pull apart under

its own weight. To avoid collapse, water may be run into the pipe from time to time, maintaining it partially full.

Usually the stovepipe string will be carried to some predetermined depth if the stratigraphy is known, if not, to as great a depth as possible; though the limitations previously mentioned in describing this type of casing preclude its use to depths in excess of 1,000 ft. under ordinary conditions.

When a depth is attained beyond which it is undesirable or impracticable to carry the stovepipe string, its shoe will be grounded, if possible, in some hard stratum so that there will be no danger of the column sinking farther into the hole during subsequent drilling operations, under the influence of its own weight. After landing the stovepipe string in this way, or after it has become permanently frozen, the top is cut off level with the casing sills in the cellar so that it will not interfere with manipulation of smaller strings of pipe, and preparations are made to continue drilling with a smaller size of drill. Second and later strings of casing are nearly always of screw pipe, stovepipe being more difficult to handle at depth because of its tendency to pull apart. Then, too, it is not of sufficient strength to withstand the pressures to which it is ordinarily subjected in deep-well service.

If stovepipe is to be inserted into an open hole more than 200 ft. deep, it is better practice to support the column from the bottom while it is being lowered, rather than at the top. In this case, it is lowered on a smaller string of screw casing or tubing and is supported at or near its lower end by a cast-iron bushing or a casing spear attached to the lower end of the tubing. If a bushing is used, it is connected with the tubing by a left-hand thread, which, after the string of casing has been lowered to bottom, can be detached by rotating the tubing. After serving its intended purpose, it is easily broken up in the well with the drilling tools. The hold of the casing spear can also be broken by rotating the tubing, but in this case the tool is removed from the well with the tubing. In this way 1,000 ft. of stove pipe may be lowered into a well without injury to the casing and without danger of pulling it apart.

Where the rotary system of drilling is employed, a somewhat different system of inserting the stovepipe string is necessarily followed. The well will be full of drilling fluid, and cementing of the pipe may be required. A more substantial form of conductor pipe, such as the Hercules corrugated sheet-metal or the thin-walled inserted-joint casing illustrated in Figs. 116 and 117 is often used. These are designed for welding and in order to reduce the number of joints are furnished in lengths of 35 or 40 ft. Having drilled and reamed the well to the desired depth and circulated the well fluid until it is reasonably free from sand and coarse cuttings, and is uniform in density and viscosity, the drill pipe and bit are withdrawn and the initial joint of pipe is started into the well through a spider or wedge block placed on the rotary table or on special supports placed across the table sills. A light steel shoe is welded on the lower end of the initial joint. When not supported by the spider, the column of conductor pipe is suspended by means of casing elevators, casing line and hoisting block from the derrick crown. Since there are no collars on stove pipe, the elevators are latched about the pipe below clamps attached near the upper end. Additional joints are welded to the column, one at a time, above the spider, through holes provided in the outer or overlapping portion of the joint. After a weld has cooled, the column of pipe in the well is lifted with the elevators sufficiently to remove the slips from the spider. The column is then lowered until the upper end is about 3 ft. above the spider, when the slips are again inserted. Lowering slightly will then suspend the column on the spider, and the elevators may be used to pick up a new joint of pipe and lower it into position for welding into the string. To expedite the work of welding, a crew of four welders may work simultaneously on opposite quadrants. Such work is often done under contract by specialized crews of welders in the employ of the manufacturers who furnish the pipe.

If the stovepipe string is to be cemented, a flange designed for attaching a cementing head is welded to the top of the column when it has reached the required depth. With the casing supported so that its lower end is a few feet off bottom, the cementing head is attached and fluid cement is pumped down through the pipe, under the shoe and up into the annular space between the pipe and the walls of the well. Where the well is to be a deep one and likely to be subjected to high-pressure conditions, enough cement may be used to fill the annular space to the surface. If this is considered unnecessary, a little cement will be placed around the casing at the surface to keep it properly centered in the hole and also to insure against gas or mud blow-outs.

After the cement has hardened, the cementing head is removed and the stovepipe cut off a sufficient distance below the derrick floor to permit of inserting a control head or blow-out preventer. This is bolted to a reinforcing flange or collar, which is securely welded to the top of the stovepipe. For added security against blow-outs, provision may also be made for attaching hold-down bolts, securely anchoring the casing to the concrete rig foundations.

Inserting Water Strings.—The second column of casing placed in the well is usually intended to be carried to a considerable depth and is generally used as a means of excluding water-bearing formations so that water from them may not enter that portion of the well which penetrates the lower oil-bearing horizons. Water strings are subjected to conditions which impose stresses of high magnitude, and lap-welded or seamless steel casing with thick walls and collared joints is necessarily used. The size is as large as can be conveniently telescoped through the conductor string in order to conserve working diameter. Being long, thick walled and of large diameter, this is usually the heaviest column of pipe to be handled. In some deep wells, water strings weighing upward of 200 tons have been used, in one case a string weighing 230 tons.

In preparation for the insertion of a long, heavy column of screw casing, when the rotary system is used, it is customary to replace the hoisting cable with a new one, and ten lines are strung on a five-sheave hoisting block. For lighter strings, six or eight lines will be sufficient. The hoisting block and hook must also be given careful inspection if a heavy string of casing is to be run.

To insure that the pipe will freely enter the well and reach the desired landing point, many operators run a reaming tool from top to bottom. Others run "feelers," often in the form of a short section of the pipe to be inserted, to assure themselves that the column will reach bottom. Some operators also under-ream for 100 ft. or so above bottom, to remove mud from the walls and leave the rock surfaces free to make proper contact with the cement. A long, heavy string of casing may be very difficult to lift without danger of parting, and every precaution is taken to be certain that the hole is of requisite diameter throughout before the pipe is lowered. With the same purpose in view, the drilling fluid in the well will be thoroughly circulated to remove all drill cuttings and detrital material, and to secure a fluid of uniform characteristics throughout. This is done immediately before the drill pipe is withdrawn, after all reaming is completed and special rigging for handling casing has been assembled. The casing must be lowered to bottom as quickly as possible after circulation is stopped, otherwise clay and sand may settle and prevent the casing from reaching the desired depth. The fluid in the well should be of reasonably low viscosity and free from sand. Its density should however be high, in order that it may develop a maximum buoyant effect on the casing and thus reduce the load on the surface equipment.

With all in readiness and with the drill pipe out of the hole, the rotary table is removed and a heavy spider or casing block is placed on heavy timbers resting on the table sills over the well. Often the casing block will be permanently mounted on a timber or steel sled. If the column of casing to be lowered is not too heavy, the table

slips may be used to support the pipe or a casing block may be placed on top of the table. The first joint of casing lowered into the well has a suitable casing shoe welded, riveted or screwed to its lower end. Often a cement shoe, equipped with a float valve, such as that illustrated in Fig. 119 and described on page 288, will be employed. In addition, a float disk carrying a downward-opening valve may be placed in a casing collar, a joint or two off bottom. The special shoe and collar are designed to assist in the subsequent cementing operation and also serve to close the lower end of the column, preventing admission of the well fluid so that the pipe may be "floated in." The surface equipment is thus relieved of a large part of the load that it would otherwise have to bear.

The shoe joint, suspended on the elevators and casing block, is lowered through the spider until the open collar on the upper end is about 3 ft. above the derrick floor. The spider slips are then dropped into position and the joint again lowered until the slips take hold. The elevators are detached, a new joint of casing is brought in from the rack outside the derrick and up-ended by hoisting on the elevators until its lower end swings freely above the collar of the shoe joint suspended in the spider. The thread protector on the lower end of the new joint is removed, a thread compound is applied to both parts of the joint and the new section of pipe is then lowered carefully into the collar on the upper end of the pipe supported in the spider, avoiding abrasion of the threads. The upper joint of pipe is given a few turns by hand, using a rope sling and bar if necessary. When the threads have engaged and it is certain that they are not cross-threaded, casing tongs are applied, first by hand, then with the aid of the power, until the joint is securely made up. The power may be applied by means of a line spooled over one end of the rotary catheads, or, in the case of the combination or standard rigs, with a jerk line attached to the wrist pin on the crank. For small and medium-sized casing one pair of casing tongs will be sufficient, but for large sizes two may be used. Some operators make up casing joints with a "spinning rope," several wraps of the rope being taken about the pipe above the joint and power applied with one of the rotary catheads. Some rotary tables are equipped with features designed to assist in making up and breaking down drill pipe, which may also be used on casing when the latter is of small or moderate size. Some special types of rotary equipment such as the Hydril (see page 254) are particularly designed to assist in casing operations. The driller's judgment will largely determine when the joint is secure, though some operators insist that all threads should be "buried in the collar," while others judge by the temperature developed in the collar. When the joint is securely made up, the column of pipe is lifted slightly until the spider slips can be removed and then lowered until the top of the new joint is about 3 ft. above the spider. The slips are again inserted and the casing in the well suspended on the spider. This process of adding a new length of pipe to the column in the well is continued, joint by joint, until the shoe on the lower end reaches bottom.

An augmented crew is generally employed in running casing, often from 7 to 10 men. The several members of the regular rotary crew work in their usual places: one at the draw-works and engine controls, three on the derrick floor and one in the derrick. In addition, when a combination rig is used, a cable-tool crew of two men may be employed in operating the standard engine and jerk line from the crank in making up joints. Additional men may be used in rolling casing down off the rack and bringing it into the derrick, removing thread protectors and doping joints. With a skilled crew, the work moves with clock-like precision. From 8 to 20 joints per hour are made up, depending upon the size of the casing. Wells 6,000 ft. deep may thus be cased in from 15 to 30 hr. with large-diameter pipe; in one instance, 6,237 ft. of 11¾-in., 60-lb. casing was placed in a well in 13 hr. The rate of progress, expressed in footage, will depend upon the length of joints, the time necessary being nearly halved through the use of 40-ft. joints instead of 20-ft. joints. The longer joints are

uncommon, though where there is room to stand casing in the derrick, some operators make up 40-ft. "doublers" and stand them on end in the derrick so that actual placing of the casing in the well may be accomplished in the shortest possible time. This, however, is practicable only when small-diameter pipe is in use.

When the column of casing is floated in, it is customary to keep the pipe only partially full of drilling fluid. As much as 2,000 ft. of pipe may be left open to develop the desired buoyancy when a long column of heavy pipe is to be set, but usually 500 to 1,000 ft. will be sufficient. As the column of pipe is lowered into the well, fluid is of course displaced so that there is, with each lowering of the pipe, a flow of drilling fluid upward, which assists in keeping it free of the walls. With the purpose of reconditioning the fluid and offsetting the tendency of solid components to settle out, some operators occasionally attach a circulating head to the top of the casing column, circulating new fluid down through the pipe, under the shoe and back to the surface. This is particularly desirable when the lower end of the column is nearing bottom, it often being necessary to "circulate in" the last few joints when sufficient time has been occupied in the casing operation to allow the mud to settle. If the casing tends to become "logy," a little crude oil or Aquagel added to the recirculated fluid will assist in keeping it free. In a deep well it may be somewhat uncertain just when the casing shoe reaches bottom unless careful measurements have been made of the depth of the hole and the length of pipe inserted. A weight indicator, such as that described on page 220, will assist in determining this.

The column of casing is finally suspended with the lower end a few feet off bottom, and preparations are made for cementing (the cementing process is described in detail in Chap. X). When the cement has set and hardened, tension equal to the weight of the column is taken from the upper end and maintained by attaching a suitable head device, which bears on the upper end of the conductor casing. These head supports provide massive bearing flanges with packing compressed between, or, in some patented forms, mechanical stuffing boxes in which the inner casing is supported on slips which may be placed to take hold at any desired point (see page 430).

When the cable system of drilling is employed, the procedure followed in inserting casing is much the same as that described for the rotary-drilled well in the foregoing paragraphs, except in so far as modifications are required by the nature of the equipment available and the condition of the hole. With the cable tools, casing is handled on elevators and a hoisting block strung on a steel line passing over casing pulleys at the derrick crown and thence to the shaft of the calf wheel. If no calf wheel is provided as a part of the rig, the casing line is attached to the bull-wheel shaft. If the formations are hard and do not show a tendency to cave, the hole may be drilled to its full depth before any casing is inserted, but, if the formations are unconsolidated, it will be necessary to carry the casing along with the drilling, adding a joint or two at a time as drilling progress permits. The column of pipe in the well is suspended on a casing spider, which is often placed on timber supports in the bottom of the cellar, so that the upper end of the casing can be kept below or level with the derrick floor and thus be out of the way of all operations in the derrick. As the hole is deepened, drilling will be interrupted occasionally to add more casing to the column so that the shoe is always kept below the jars. The advantage offered by the casing spider, of being thus enabled to lower the casing gradually as drilling proceeds, is often helpful in penetrating a caving formation, allowing the tools to work on bottom without interruption. This procedure is possible with the cable tools because in soft formations they are capable of drilling a hole of larger diameter than that of the casing through which they operate. When hard strata are encountered, in which the cable tools tend to drill a smaller hole, it may be necessary to under-ream before the casing shoe can pass through.

Additional Water Strings.—If four strings of casing must be used in a well, as may be the case where the well is a very deep one, where formations developing caving conditions must be contended with, or where upper oil and gas sands must be protected, the strings intermediate between the second and the last are also regarded as water strings and are inserted in the manner described in the previous section. These additional water strings are customarily cemented, and in many cases sufficient cement will be used on the smaller inner strings to fill the annular space up to and preferably somewhat above the shoe of the outer, larger water string. The space between the two columns of pipe may then be filled with mud fluid. This practice transmits the outside collapsing pressure to the inner water string which, by virtue of its smaller diameter, is better able to sustain it.

Inserting Casing by Welding Joints.—The process of inserting a string of pipe, the joints of which are oxyacetylene welded, is necessarily quite different from that described above for collared-joint casing. The pipe must first be prepared for welding. As already explained, plain-end pipe is used, and unless it is properly beveled for welding in the mill where it is made, each joint must be placed in a lathe, machined to square ends and then beveled on the outside for two-thirds of the thickness of the pipe. In order to reduce the number of welds made in the derrick, the pipe is welded into two-joint stands and three or four lugs are welded on the outside of each stand near one end so that the elevators may be used in suspending it in the derrick.

The first stand is hung in the well on slips, either in the rotary table or a casing spider, and a rod of welding iron, bent into a U-form, is laid across the upper end. The next stand has meanwhile been hoisted into the derrick on the elevators and is lowered on the U-shaped rod, which serves to space the two joints at the proper distance apart for welding. Spacing of the ends in this way leaves room for expansion, so that the casing will not be thrown out of alignment when making the weld. Two welders work on opposite sides of the pipe, an arrangement which also aids in preventing crooked pipe as a result of unequal expansion. After the casing is aligned, two "tacks" are spot-welded on opposite sides of the joint, after which the welding metal is fused, beginning at positions 90 deg. from the tacks. The space between the square ends of the joints is first filled with metal, after which the corners of the beveled portion are rounded off to increase the surface of contact, and the space between the two joints is filled flush with the outer cylindrical surface. After the weld is completed, the lugs on the lower joint are cut off with the cutting flame, the weld is allowed to cool and the casing is lowered on the elevators for the next weld. Another type of welded joint makes use of a short reinforcing tube spot-welded on the inside of the joint.[7]

With 8¼-in. casing, about 1 hr. is required for each weld (that is, for each 40-ft. stand). Welding saves about $5 per joint (for 8¼-in. pipe), by eliminating collars and threads, but this is partially offset by the cost of beveling the ends for welding. The extra cost of labor and materials used in welding, however, about equalizes the saving effected. Eight hours is necessary to run in 300 ft. of 8¼-in. pipe, as against 1½-hr. for a like amount of screw casing. Two welders, one helper and a drilling crew of five men are necessary in conducting the work, while steam supply, oxygen, acetylene, welding iron, etc., must also be taken into account. In the case of a well equipped with a welded liner in one of the California fields, the additional labor and materials amounted to about $75.

It is claimed that welded liners will stand more jarring and pulling than collared joints without danger of parting, do not freeze so readily and that there is less loss of working space in the well because of elimination of the collars. In removing a welded liner from the well, it must be cut apart in stands of convenient length. This may be done with the cutting torch but is preferably accomplished with pipe cutters which leave the ends straight and properly beveled for welding when the string is replaced.

Landing Casing.—When a string of pipe has been carried to as great a depth as is necessary, or as is deemed desirable, and a change in the diameter of the bore is to be made, the casing must be properly supported so that it will not follow down the hole under the influence of its own weight during subsequent drilling operations. If possible, a stratum of hard rock will be selected in which to land the column of pipe, and a slightly smaller hole will be drilled a few feet ahead, into which the casing shoe will be driven. When the change is made to the smaller size of bit to be used in drilling the next section of hole, the casing will be supported on a narrow shoulder of hard rock and with the shoe thoroughly embedded in it (see Fig. 154).

Cementing Casing.—If a string of pipe is to be used to exclude water, the procedure is somewhat different. The method of landing the pipe described in the preceding paragraph may be successful in excluding water (see "Formation Shut-off" on page 355), but most operators prefer to exclude water by surrounding the casing at its lower end with a plug of cement, which completely fills the space between the casing and the walls of the well. The cement is placed, by methods to be described in detail in Chap. X, with the casing shoe a few feet off bottom; but the shoe is lowered to bottom and driven into a tight hole previously prepared for it before the cement has taken its initial set. This leaves a few feet of cement which must be later drilled out of the casing. A period of from 4 to 16 days is usually allowed for the cement to harden before drilling is resumed.

Perforating the Oil String.—The last column of casing to be placed in the well is that which penetrates the oil sand and is therefore called the "oil string" or "liner." This pipe must be perforated with a series of round holes or slots, opposite the oil-producing stratum, in order to admit the oil to the pump. The pipe may be perforated in the shop before lowering it into the well, or the openings may be made in the well with the aid of a casing perforator. The methods of perforating casing, the placing of screens and other details incidental to the completion of the well and preparing it for production, are to be described in Chap. XI.

Salvaging Pipe in Casing a Well.—It is not necessary that all strings of casing in a well come to the surface. Unless water is to be excluded by a column of casing, it may be cut off about 50 ft. above the shoe of the preceding string and considerable casing salvaged (see Fig. 130). A water string, however, must always extend to the surface so that water may not accumulate behind it and overflow into the lower part of the well. A string of pipe which is not intended to extend to the surface may have placed in it at the proper point a "bell collar" having left-hand threads in one end, so that by rotating the column of pipe after the shoe has been placed on bottom the column is broken at the bell collar and the upper end is removed. Casing may also be cut at any desired

point by the use of a tool made for the purpose and called a "casing cutter" (see Fig. 138).

DIFFICULTIES ENCOUNTERED IN HANDLING CASING IN THE WELL

Casing difficulties are the result of either freezing, collapsing, telescoping, parting or splitting. Freezing results from caving of the walls against the pipe, accumulation of mud around the casing collars, contact with the walls in a crooked hole or failure properly to ream a tight place in the well. Collapse of the casing is due to external pressure, generally hydrostatic pressure; though caving of the walls or a loose bowlder in the walls bearing against the pipe as it is forced down may deform it. Telescoping of a column of pipe may result from dropping it accidentally, or, in the case of stovepipe, by driving it too severely at the top when the lower end is frozen. Parting, or pulling apart of a column of pipe, may be the result of extreme tensional strain engendered by its own weight or by trying to pull it up when it is frozen. It may result from defective threads or from failure to couple the joints properly; or the lower end of the column may be loosened by turning the pipe in the well, or by the jar resulting from hammering on its upper end in driving it down. A column of stovepipe may pull apart by failure of the picked joints to hold together. Premature explosion of a charge of dynamite or nitroglycerin will generally part the casing opposite the point of explosion. Splitting of casing usually indicates defective welding in the manufacturing process, but it may be caused by drilling out material which has "heaved up" from the bottom into the casing, or it may result from the use of a swedge, casing spear or other fishing tools (see pages 323 and 325). Most of these difficulties may be avoided by proper selection and inspection of casing and care in coupling the joints together and lowering the column into the well. Good judgment is also necessary in determining to what depths a string of pipe may be carried under the conditions applying and what strain can be safely put upon it. The condition of the walls of the well, whether or not the hole is crooked, or if all tight places have been adequately reamed, will also have an important bearing on the success of a casing installation.

Freeing Partially Frozen Casing.—If the casing develops frictional contact with the "formation," that is, if it shows indications of being collar bound with mud and loose material from the walls, it can often be freed by alternately raising and lowering a few times for a distance of 20 or 30 ft., working the loose material past the collars and shoe so that it falls into the bottom of the well. If this fails to relieve the friction on the pipe, the well may be bailed down within the casing so that hydrostatic pressure aids in clearing the space about the pipe; or a hole may be drilled ahead of the casing shoe so that there is adequate space into which the mud may flow. The pressure conditions may be reversed by placing a circulating head on the top of the casing and pumping water

down through it under pressure in the hope of establishing circulation back to the surface through the space around the pipe. If circulation can be established, the mud will be gradually removed by the upward current. If difficulty is found in securing circulation under the pump pressure available, a slit cut in the casing shoe or in the pipe immediately above is often effective.

If friction on a column of casing is due to an effort to lower it through too small a hole, the best remedy is to pull the pipe up until the shoe is above the tight place and under-ream it thoroughly. Under such conditions, particularly if the pipe has been driven, it is often impossible to lift the column against the friction with the power available from the calf wheel and hoisting blocks, or without placing undue strain on the derrick. In such a case a combined pull and jar is often successful where a simple pull fails. This is accomplished by lowering a casing spear (see description of spear on page 325) below the stem and a pair of fishing jars, taking hold with the spear inside of the pipe near the bottom and jarring up with a long stroke of the beam. Tension is meanwhile held on the casing with the hoisting blocks and elevators (see Fig. 133), or a lifting force may be applied to the casing by means of screw or hydraulic jacks.[5]

Driving Casing.—If friction on the pipe is thought to be due to a crooked hole, or if it has been gradually increasing and the landing depth selected has been almost reached, the pipe may be driven from the surface in the hope of reaching the required depth before the pipe becomes completely frozen. Alternate driving and pulling of casing is also effective in freeing it from wall friction. Driving the casing down will often leave a free space above the collars, so that the pipe can be readily drawn back the same or often a slightly greater distance. Alternate driving and pulling back in this way will in many cases gradually free frozen casing until it can be moved up and down the length of a joint of pipe, when it should pull quite freely. In driving casing, "spring" and "vibration" of the pipe are the means of loosening the enveloping sediment. The method of driving casing from the top with the drive clamps and head has already been described. Driving from the top is likely to be detrimental to the pipe, often loosening the joints, or in some cases stripping threads in the collars; furthermore, much of the force expended at the top of the column is absorbed at depth by the elasticity of the pipe.

A long column of pipe can be driven more satisfactorily by applying the vibration near the bottom instead of at the top. This can be accomplished through the use of the jar-down or drive-down casing spear. (See Fig. 132*D*.) The tools are strung as in fishing, with long-stroke fishing jars below the stem and with the spear screwed on the bottom of the lower link of the jars. The slips on this spear are so constructed that they slip up a conical recess and out against the inner face of the casing, preventing the tools from going farther down the hole. The process of driving down with this equipment consists simply in gripping the casing with the spear at the desired depth and operating the walking beam with a stroke sufficient to cause the jars to strike on the downstroke. The position of the spear must be changed frequently to prevent the pipe from becoming distorted by the outward pressure of the spear slips.[5]

Lubricating Casing with Oil to Reduce Friction.—Observation has shown that pipe will freeze less readily in rocks saturated with oil, and in some instances petroleum

has been circulated in wells with the hope of reducing friction of the walls against the pipe. This method has apparently met with some success in certain California fields where it has been found possible, by circulating oil, to keep a long string of pipe fairly free in the well, while ordinary unlubricated casing in the same territory freezes rapidly. It seems probable that the oil saturates the material in the walls, rendering them more plastic, thus releasing the hold on the pipe. Furthermore, loose sand, which tends to pack about the casing collars in the presence of water, remains in suspension in oil. Casings, apparently firmly frozen, have been released by circulating oil with pump pressure under the shoe and back to the surface. In one case a column of 12½-in. casing was frozen in a 15-in. hole and the derrick was "pulled in" in attempting to release it. After the derrick had been rebuilt, oil was circulated for 3 days and the string was readily pulled out.[4]

The dangers involved in pulling on frozen casing are well understood by most drillers. When one considers the great mechanical advantage of the ordinary band-wheel, calf-wheel and hoisting-block combination—ordinarily about 144 times the lifting force of the engine—it is apparent that we are dealing with a force of great magnitude, sufficient either to pull the pipe apart or collapse the derrick. Men have been killed or injured by the collapse of the derrick or by contact with the calf line, hoisting blocks or elevators in the sudden release of tension when the casing pulls apart near the surface. The equipment should be operated from the engine house in pulling casing.

Parting and "Sidetracking" Frozen Casing.—Should it become impossible, by any of the methods suggested above, to move the pipe either up or down in the hole, and it is essential to continue to a greater depth with the size of pipe in use, the pipe must be parted above the point at which it has become frozen and the lower end "sidetracked." It is possible to locate approximately the depth at which the pipe is frozen by lowering a fishing string and jar-down spear, taking hold inside of the pipe at intervals, jarring, and noting the change in character of the vibrations produced in the pipe. When the spear takes hold above the "friction," the jarring produces a metallic ring in the pipe that is quite absent when the spear is attached below. Knowing the approximate depth at which the casing is bound, it may be cut with a casing cutter, or ripped with a casing slitter or perforator, and pulled apart a short distance above; or, it may be parted with a charge of dynamite or nitroglycerin. The explosive should be used in small quantities—10 to 15 lb. of 40 per cent dynamite is sufficient in most cases. The upper end of the column of pipe may be withdrawn after parting by either of these methods, a new shoe placed on the bottom and the column replaced until the new shoe is about 75 ft. above the top of the parted string. The lower part of the well is then redrilled, proceeding cautiously until the detached column of pipe is passed.[5]

"Sidetracking" Casing.—When a portion of a string of pipe has been either accidentally or intentionally parted and it is found to be impossible for one reason or another to remove it from the well, an effort must be made to drill past the parted string. This may be a difficult procedure in hard rocks, but is easy of accomplishment in soft formations. Since it is necessary for the new casing to make a slight bend in passing the old pipe, an effort should be made to enlarge the hole by under-reaming for a distance of 60 or 75 ft. above the top of the parted pipe. The drilling tools are then put to work as in ordinary drilling, upon the top of the old pipe, gradually battering and distorting it until the tools work off to one side. Difficulty is often encountered in getting the new casing shoe to pass the top of the old pipe, but turning the string at the surface will often allow the shoe to slip past. Once by the upper end of the parted column, little difficulty results, the new hole being drilled at one side of the parted column and the latter eventually cased off. Contact between the collars or ragged edges on the parted string and the shoe on the new string may

cause slight delays, but patience in manipulating the casing at such times will usually overcome the difficulty. Various types of reamers and eccentric bits are used by some drillers in sidetracking pipe to aid in enlarging the hole and clearing the way for the new pipe. Often, better progress is made in drilling by the old pipe than in drilling the original hole. In some cases, hundreds of feet of casing are successfully sidetracked in this way and occasionally several separate sections of pipe will be cased off in a single well. The method described may also be employed in sidetracking lost drilling tools or other well equipment impossible to recover by fishing.

Operations involved in the repair or replacement of collapsed, telescoped or parted casing partake of the nature of fishing, and are reserved for description in Chap. IX devoted to Fishing Tools and Methods.

Measuring Casing. Stretch and Sag in a Column of Pipe.—It is occasionally necessary to know the exact length of a string of pipe or the precise depth at which the shoe of the string is located. The repair of old wells, the exclusion of water occurring in strata immediately above an oil sand or the depth at which to place perforated pipe, detonate explosives or apply casing cutters or other special tools, are operations which often require fairly exact casing measurements. In order that such information be available, it is a good plan to record it as a part of the log of the well (see page 450), which is carefully preserved as a record for future reference.

While it is possible to determine approximately the length of a column of pipe by measuring each joint that goes into it (length from top of collar to top of lower threads), the sum of such measurements will seldom give the exact length of the column owing to variation in the length of threaded ends in the couplings. A better method is to measure the length of each stand or joint with a steel tape after the joints have been "set up" with the tongs and are ready to be lowered into the well. Even such a measurement is not altogether reliable if it is to be used as a means of correlating with a stratigraphic record, say, in determining the precise depth at which to make a water shut-off or to place perforated pipe opposite an oil sand. This results from the "stretch" of a column of casing under its own weight, which tends to make the column longer than the tape measurement would indicate; and the "snaking" of the pipe in the hole, which results in some cases in a somewhat greater length of casing being placed in a hole than the actual drilled depth. An approximate calculation of the elastic elongation of a column of pipe hanging free in a well, for example, indicates that 6,000 ft. (tape measured) of steel pipe, would actually be 24 in. longer. Linear expansion in a column of this length subjected to an average increase of, say, 50°F. in ground temperature, will add another 23 in. to the length of the pipe. It is a matter of common observation, in pulling a column of casing out of a deep well, that several feet, or, at times, even a joint or more may be pulled up at the surface before the full weight of the pipe is felt. This can be nothing else than stretch in the pipe, or surplus

pipe that results from "staggering" of the casing from side to side in the hole. Many drillers consider a stretch of 1 in. to 100 ft. a normal elongation in pulling frozen pipe. If a well departs from the vertical, by say 5 deg. in a depth of 3,000 ft., the bottom may actually be 12 ft. nearer the surface than the length of the pipe in the hole would indicate.

The actual depth to the lower end of a column of casing may be checked by an independent measurement after the column is in place in the well, if precise data are necessary. In such measurements it is customary to lower some tool—such as a ripper, an under-reamer, a latch jack or a specially designed hook—which can be made to catch on the lower edge of the casing shoe, carefully measuring the length of the cable on which the tool is suspended. An under-reamer of the same size as the casing gives especially satisfactory results. The lugs expand after passing below the shoe, and on pulling up the tool so that the lugs strike against the shoe the resulting vibration indicates definitely its position.[9]

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CHAPTER IX

FISHING TOOLS AND METHODS

The recovery of tools, cables, pipe and rods that have become detached while in the well, or that have been accidentally dropped into the well, and the repair of damaged casing, are operations that require the highest skill and ingenuity of the driller. In many cases, the completion of the well hinges upon success in recovering the lost equipment or making the necessary repairs. Days, weeks or even months may be spent and large sums of money expended in fishing operations.

A great variety of special tools have been devised to assist in such work, some of which are described and illustrated in the present chapter. Only the more common fishing tools will be discussed, and these but briefly, it being quite impossible, in the space available, adequately to describe all of the many tools that find application in fishing operations. Indeed, many of these tools are but rarely used; in some cases a tool will be made for a particular purpose and never used again. Only the largest operators can afford to own more than a limited assortment of such tools because of their great cost and limited use, and many operators make a practice of renting them from local supply houses as they are needed. The technic of fishing is mastered by comparatively few drillers, and the industry is developing specialists in this work, who undertake the recovery of lost tools or the repair of damaged casing under contract.

One might suppose that the loss or breakage of a tool in the well, or the parting or collapse of a string of casing, is the result of carelessness and might be avoided by proper design and care in the conduct of the work. While this is true to a large extent, it must be recognized that such accidents are a natural hazard; that they are inherent from the very nature of the work and therefore can never be entirely overcome. However, proper care in handling the equipment and frequent and thorough inspection of cables, casing, drill stem, tools and tool joints will greatly reduce the number and frequency of fishing jobs. Drilling cables and sand lines should be watched carefully for signs of weakness or unusual wear; drilling tools, drill stem and casing should be inspected for incipient cracks, particularly at welds; and no equipment or tools should be lowered into the well unless, as far as can be detected, they are in perfect condition. In anticipation of the inevitable fishing job, it is a good plan to fully record the dimensions of everything used about or in the well so that information will be at hand for designing or selecting a suitable fishing tool.

We may classify the various fishing tools to be described, according to the purposes for which they are intended or the nature of the operations in which they are used. There is a large group of fishing tools designed for recovering various parts of the string of cable drilling tools; another group is intended chiefly for taking hold either on the inside or outside of hollow cylindrical objects, such as casing, bailers or rotary drill stem;

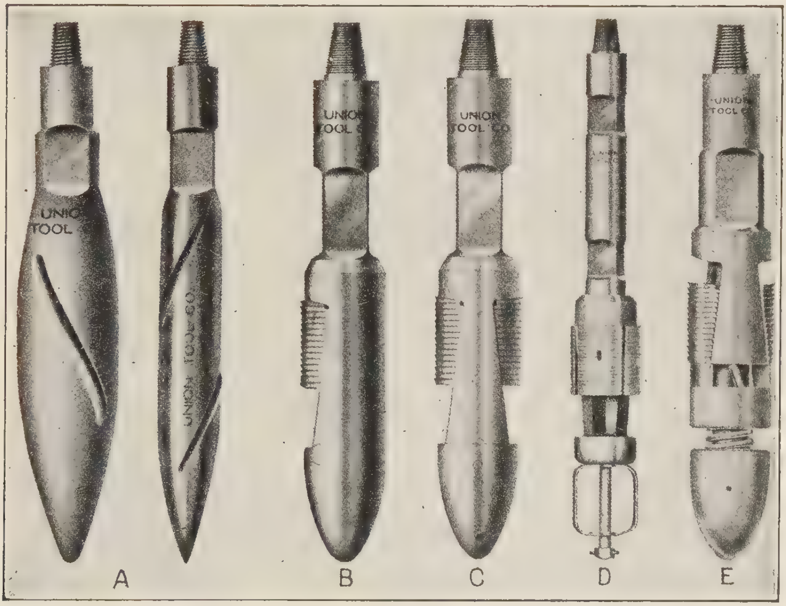


Fig. 132.—Types of casing swages and spears.

A, casing swages; *B*, bulldog single-slip spear; *C*, bulldog double-slip spear; *D*, drive-down trip spear; *E*, Fox trip spear.

still others are designed to expand, cut, rip or perforate casing; and there are also a number of tools used in recovering or cutting hemp rope or steel cable in the well.

REPAIRING AND RECOVERING DAMAGED CASING

The difficulties encountered in handling casing in the well were outlined in Chap. VIII. The methods of releasing frozen casing were there discussed, but the methods of repairing collapsed, parted and punctured casing were deferred until the present chapter.

Collapsed Casing

Use of the Casing Swage.—Collapsed casing, which has been partially flattened, dented or otherwise distorted from its original cylindrical form as a result of abnormal external pressure, can often be brought back to its original form by driving a casing swage through the collapsed section. Common types of casing swages are illustrated in Fig. 132. They

have solid cylindrical bodies, pointed at the lower end and equipped at the upper end with a tool joint for connecting with the lower link of the jars. A spiral groove or water course is cut in the cylindrical surface to allow the well fluid to pass as the tool is lowered down through the pipe. The maximum diameter of the cylindrical body of the swage is but a fraction of an inch smaller than the diameter of the casing for which it is designed; thus, casing with a 10-in. inside diameter should permit the passage of a swage 9⅞ in. in diameter.

Special types of swages include the Hinderliter hollow swage and the Oilwell roller swage. The former has a passageway through it, so that it can be lowered through a stream of flowing gas, water or oil. The roller swage is designed to reduce the great friction characteristic of most swaging operations, being equipped with a series of small rollers mounted on horizontal pins with the outer cylindrical surfaces of the rollers projecting slightly beyond the body of the tool.

The swage is attached below long-stroke fishing jars, and the latter is attached to the lower end of the drill stem.[1] The tools, thus connected, are lowered into the well until the swage encounters the collapsed or dented portion of the pipe. The weight of the tools is then transferred to the walking beam, the jars being permitted to telescope and strike on the downstroke. As the swage is driven ahead by the impact of the stem and jars, the temper screw is let out sufficiently to keep the jars striking on the lower end of the downstroke. When the swage has been driven through the collapsed section and has entered the undisturbed pipe below, the tools swing freely, resulting in an unmistakable change in vibration and cable tension. The swage must now be drawn back through the collapsed section and will probably have to be jarred back by permitting the jars to strike on the upstroke. The swage should be driven down and back through the pipe until it can be pulled through without jarring.

When it is thought that the pipe is badly flattened, it is preferable to drive a swage of smaller diameter through first, and the full diameter of the pipe attained through the use of successively larger swages. The swage sometimes becomes wedged in the casing, and if the pipe is split, either by collapse or by the pressure of the swage, a most difficult situation may result through loose débris entering above the swage and wedging about it.

Recovering Parted Casing

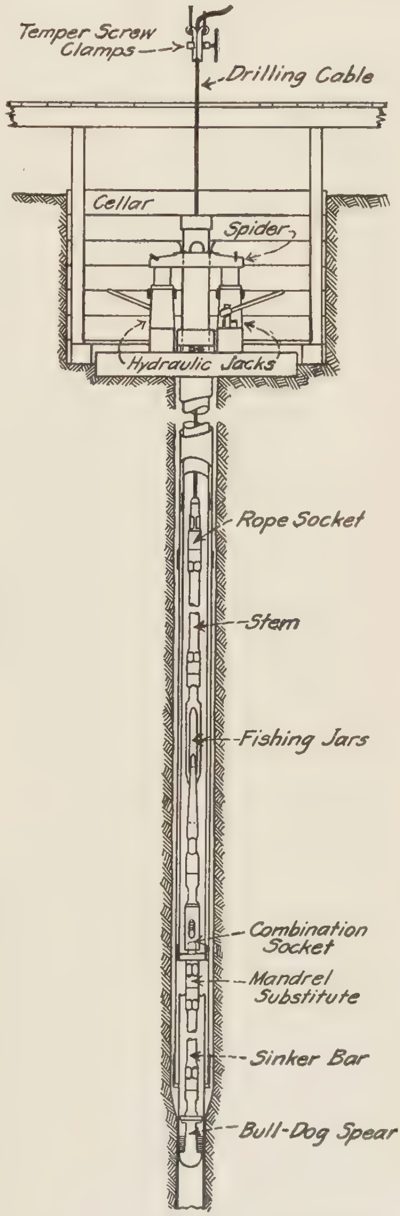
When a string of casing has pulled apart in the well as a result of a defective joint, insufficient thickness of metal, severe tensional strain—as in attempting to pull it out of the well when the lower end is frozen—or when it has been purposely parted with the aid of a casing cutter, ripper or explosives, either of several different tools may be used in recovering the lower end. If the condition of the well and the casing permits of withdrawing the pipe to the surface to join the parted ends, this method is generally preferred and for this purpose use may be made of either a casing spear, which takes hold inside of the pipe, or a casing bowl or overshot, which takes hold on the outside. If there is reason to expect that the upper end of the parted column is splintered or irregularly fractured, as often happens when casing is parted with explosives, a mandrel socket may be preferable. If it is considered best not to remove the parted

string from the well, connection may be made with it by a new string lowered from the surface, with a die nipple placed on the lower end.

Use of the Casing Spear.—There are many types of casing spears designed for taking hold on the inside of a column of pipe, but they can all be classified into two groups: (1) bulldog spears, which have no mechanism for releasing the spear once it takes hold, and (2) trip spears, which may be readily released, either by turning the tubing on which they are lowered, or by driving down upon them with the fishing jars.

Common forms of casing spears are illustrated in Fig. 132. They consist usually of a substantial cylindrical steel body, pointed somewhat at the lower end to guide the tool into the pipe which it is to recover, and equipped with a pin joint at the upper end for connection to the fishing jars or drill stem. Inclined planes are machined out of the cylindrical body for either two or four slips, the slips operating in grooves and keyed to a mandrel extending up through the body of the tool. In the case of the trip spear, the mechanism controlling release of the slips must be built inside of, or below, or above, the main body of the tool and often consists of a spring device operated by a latch or trigger, which can be tripped by revolving the tool or by driving down upon it with the jars.

In using a spear to recover parted casing, the tool is screwed to a mandrel and the latter is attached to the lower end of the jars. If the spear to be used is of the bulldog type or a type of trip spear that is released by the jars, the fishing string thus assembled may be lowered on the drilling cable. If a trip spear of the type that is released by turning is to be used, it must be lowered on a string of tubing and a substitute is used in connecting with the fishing string above the jars. When the tool has entered the open end of the parted pipe, it is raised until the slips slide down the beveled supports and bind against the walls of the pipe.[1]



(*After T. Curtin in U. S. Bur. Mines, Bull.* 182.)

FIG. 133.—Fishing string for applying combined jar and pull on casing.

A trip spear should be used in preference to one of the bulldog type when there is any possibility of the casing being frozen or otherwise difficult to remove from the

well. A bulldog spear can be driven farther into a pipe but cannot be pulled out once it has been lowered, unless the pipe comes with it, without damaging either the spear or the pipe. Even the trip spears are apt to become "bulldogged" in the pipe by failure of the tripping mechanism to work properly or by caving of material from the walls above. When it is necessary to break the hold of a spear, the slips can often be worn smooth by "hitching on" to the beam and jarring both up and down, rasping the slips against the pipe. Such action, however, is apt to damage the pipe. In some cases the slips break and fall into the well so that the main body of the tool can be withdrawn. The slips can usually be broken off if necessary, in order to remove the tool, by driving the spear down until it passes below the casing shoe and then jerking up so that the slips strike the lower edge of the shoe. Pressure of the slips against the casing is apt to cause bulging or splitting of the metal. For this reason, the position of the spear should be changed occasionally.

The use of a casing spear in jarring on frozen pipe has already been described (see page 318). A somewhat similar plan is occasionally followed when the lower

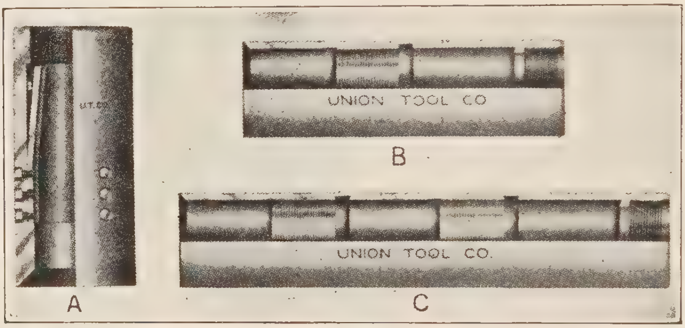


FIG. 134.—Fishing tools for recovering casing or rotary drill pipe. *A*, overshot; *B*, single-slip casing bowl; *C*, double-slip casing bowl.

end of a parted string of pipe has become frozen in the well (see Fig. 133). A spear is attached to the lower end of a short stem, and the latter is attached at its upper end to a substitute equipped with a mandrel projecting upward at its center. The substitute is screwed into a casing collar, and the tools thus assembled are lowered on a column of casing of the same size as the parted string in the well. When the spear has entered the upper end of the parted section of pipe and has taken hold, two hydraulic jacks are rigged under the casing spider in the cellar and tension is applied to the pipe. A second fishing string, consisting of a combination socket (pp. 336–337), fishing jars, stem and rope socket, is then lowered on the drilling cable and a hold taken with the combination socket on the mandrel, which projects above the substitute. The latter string is then hitched on to the walking beam and the stroke adjusted so that the jars strike on the upstroke. This combined lifting force, or pull of the hydraulic jacks, and jarring action is often effective in freeing the casing.

In addition to its use in recovering casing, the spear may also be used in recovering a lost bailer the bail of which has pulled out, or a rotary drill stem, well tubing or any hollow cylindrical object to the inside of which access may be had from above.

Use of the Casing Bowl.—The casing bowl is a hollow, cylindrical tool equipped with internally placed slips which can be lowered over a cylindrical object and a hold taken on the outer surface. One successful type of casing bowl (see Fig. 134) has three slender slips mounted in machined inclined grooves on the inner surface of a steel cylinder.[1] If the parted section of pipe has no collar on the top joint, a bowl of proper size can be lowered over the end and a hold taken sufficient to withstand considerable pulling. It may be used instead of a die coupling or collar (see page 328)

in cases where it is desired merely to connect with a detached string of pipe in the well without pulling it out. This tool has not sufficient strength to permit of driving, and is not water-tight.

A rotary casing bowl manufactured by the Hinderliter Tool Company is equipped with a slender slip designed to engage when the tool is turned to the left. The tool is available in two models, one of which operates on the inside of the detached pipe and the other on the outside.

Use of the Overshot.—If a collar has been left on or near the upper end of a parted string of casing, the overshot may be used in recovering it. This is a tool equipped with three or four flat springs held erect within a steel bowl (see Fig. 134). It is suspended on the lower end of a column of pipe of greater diameter than the detached

Fig. 135.—Bell socket.

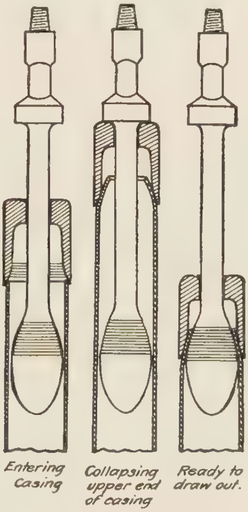


Fig. 136.—Illustrating application of bell socket.

string in the well. As it is lowered, the bowl guides the tool over the upper end and the springs press inward against the parted string. It continues to descend, telescoping over the parted section of pipe, until the springs slip under the lower edge of a collar, when on pulling up on the tool a hold is taken sufficient to stand severe strain. The overshot is widely used in recovering rotary drill stem that has twisted off while in the well and is also useful in picking up tubing or casing that has been dropped and is broken or crooked.

Use of the Bell Socket or Mandrel Socket.—When casing has parted and the upper end of the detached column is ragged or fractured so that the tools described above are not effective, the mandrel socket may be used. This consists of a long, hollow, tapered, cone-shaped socket, through which extends a mandrel with an egg-shaped knob on the lower end. The mandrel is free to slide up and down within the socket, and on the upper end a pin joint is forged for connecting with the jars. A shoulder turned on the mandrel just below the tool joint permits of driving down on the flattened top of the socket with the aid of the jars.

As the tool is lowered below fishing jars and a drill stem on the drilling cable, the socket passes over, and the mandrel inside of, the detached column of pipe. Driving down with the jars, with the mandrel extended below the socket as shown in Fig. 136, the upper end of the detached pipe is collapsed and forced into the conical socket,

thus partially closing the end of the pipe. On drawing up the tools, the knob on the lower end of the mandrel, now too large to pass through, grips the collapsed pipe on the inside and presses it against the inner face of the mandrel. The friction hold, thus secured, is sufficient to withdraw the pipe if it is free to come.[3]

Use of the Die Nipple and Die Collar.—Steel die nipples and die collars are used to recut threads on a detached column of pipe in the well, and may also serve as a coupling after the connection has been established (see Fig. 137). The die nipple is designed to cut a thread on the inside of a pipe or inside of a casing collar, while the die collar fits over the pipe and cuts a thread on the outside. A combination nipple is designed to operate inside of the pipe on one end, and outside on the other. These tools are made of case-hardened tool steel, too brittle to stand driving, although considerable tension may be applied if pulling is necessary. Aside from their use in cutting threads, they may be left as a permanent coupling in a string of pipe if, for any reason, it is considered inadvisable to pull the pipe out of the well after a connection has been effected. Because of the vertical grooves left in the cutting teeth

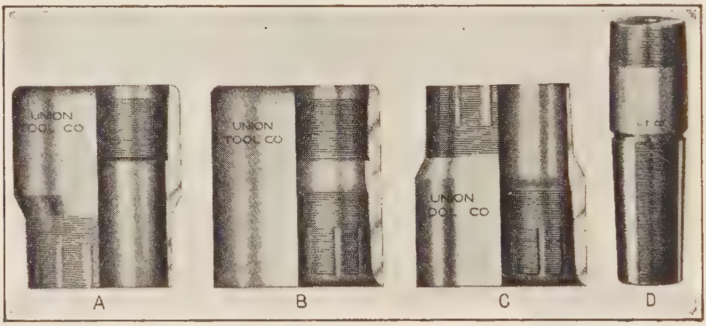


Fig. 137.—Die nipples, collars and tap for taking hold of parted casing. *A*, die nipple; *B*, die collar; *C*, combined die nipple and collar; *D*, fishing tap.

for the escape of metal cuttings, die nipples and collars are not water-tight and should not be left permanently in a water string. If a die coupling is to be used to couple two parts of a string of pipe permanently, care should be taken to select one large enough in inside diameter to pass the various drilling tools that must be subsequently lowered through it.

Die collars and nipples are lowered on the bottom of a string of pipe of the same size as the parted pipe to be recovered.[1] When the tool rests lightly upon the upper end of the detached column, the "fishing string" is turned slightly until the pipe drops into position and is ready for screwing. Pipe tongs are then applied to the fishing string with the aid of a jerk line to the crank, the weight of the upper pipe being permitted to rest upon the detached pipe. While the nipple or collar is screwed on with the engine power, a second pair of pipe tongs is used to prevent the pipe from springing back as a result of torsional strain in the pipe when the slack comes in the jerk line with each revolution of the crank. A reference mark is made on the pipe near the derrick floor to note the distance that the pipe settles after screwing begins, this being a measure of the length of thread cut unless some of the couplings in the fishing string "take up." As the die makes headway, a continuous increase in power is necessary to turn it. The point at which to stop turning is always more or less uncertain but may be inferred from the amount of tension on the tongs and the distance that the pipe has settled. The two strings of pipe are thus firmly fastened together and in condition to be pulled if desired.

Cutting or Parting Casing in the Well

Occasionally it becomes necessary to detach a section of pipe in the well. This is often done when a string of pipe becomes frozen and the lower part of the column must be sidetracked (see page 319); and in salvaging pipe during the casing of a well or in abandoning it, parting of the casing is commonly practiced. A column of pipe may be cut apart while in the well with a special tool, called a casing cutter, which is lowered through the pipe to the desired point and applied against the inner walls; or slits may be cut in the pipe with a casing ripper until it is so weakened that it can be readily pulled apart; or a charge of dynamite or nitroglycerin sufficient to part the pipe may be detonated in the well at the desired depth.

Cutting Pipe with the Casing Cutter.—The casing cutter is very similar in principle to the ordinary plumber's pipe cutter, except that it is designed to operate from the inside of the pipe instead of on the outside. The casing cutter consists essentially of a heavy cylindrical steel body into which are mortised a number of sliding steel blocks on the outer edges of which small circular, disk-shaped wheels of steel are mounted (see Fig. 138). The latter revolve freely in a horizontal plane on small metal pins set in the outer ends of the sliding blocks. A tapered steel mandrel operates through a cylindrical hole through the axis of the tool in such a way that when the mandrel is pressed down, it bears against the inner ends of the sliding blocks, forcing them horizontally outward. The casing cutter is lowered, screwed to the lower end of the column of tubing, which must, of course, be small enough to pass freely through the casing to be cut.

Before lowering the cutter, the "sag" should be taken out of the casing and a moderate tension applied and maintained by means of the elevators or casing spider. There should be enough tension in the pipe to cause the upper end to "jump" when the pipe is cut, thus indicating completion of the work to the operator. With the casing under tension, the cutter is lowered to the desired depth on its tubing. The mandrel is then connected to the lower end of long-stroke jars small enough to enter the tubing, and from two to four sucker rods are placed above the jars to give weight to the upper link. The mandrel, jars and rods, thus connected, are lowered on the sand line through the tubing until the tapered mandrel enters its recess in the casing cutter and encounters the inner ends of the sliding steel blocks that have been pressed in during the descent of the tool. The tubing is then turned by hand. The weight of the rods above the mandrel forces the blocks containing the knives out against the casing. Sometimes this weight is sufficient for the work, but when it is not and the cutter turns with so little effort that the operator is convinced that it is making little progress, the mandrel may be driven farther into the tool with the aid of the jars, by raising and dropping the sand line either by hand or with the engine power. The mandrel should not be driven between the blocks too tightly, or the tubing cannot be turned.

Usually from 20 to 40 min. turning of the tubing will be necessary to cut the casing, the upper end jumping slightly when the operation is completed because of the tension in the pipe. The mandrel and rods should then be pulled and the tubing gently raised until the sliding blocks containing the cutters are forced back into their recesses, when the cutter can readily be withdrawn to the surface.

Use of the Casing Splitter.—Lowered to the desired depth in a column of casing to be parted, the casing splitter, or ripper, may be applied in cutting vertical slits in

the pipe. Such action greatly weakens the casing, particularly if applied to the joints under the collars, so that the column can be readily pulled apart by applying moderate tension at the upper end.

The tool consists of a substantial steel body through which a recess is cut for a pointed steel knife mounted on a sliding block which slides on a steel pin in two inclined grooves (see Fig. 139). A pin joint is provided at the top of the tool for connecting with a fishing string consisting of long-stroke jars, drill stem and rope socket. A mandrel extends down through the axis of the tool and is attached to the sliding block which supports the knife. On the lower end of the mandrel a heavy

Fig. 138.—Casing cutter.

Fig. 139.—Casing ripper.

spring is placed, which when released bears against the inner walls of the casing. There are single-knife and double-knife patterns, the latter type cutting two slots at once, 180 deg. apart on the circumference of the pipe.

Before lowering the splitter into the casing, the spring (see Fig. 139) is raised on the mandrel by compressing a small trigger at the lower end of the mandrel.[1] As the tool is lowered through the casing, there is enough pipe friction upon the spring to prevent it from dropping below the trip trigger. When the tool has been lowered to the desired depth, it is then raised a few feet, thus drawing the mandrel up through the spring; the mandrel trigger snaps into place above the lower edge of the spring and the tool is "tripped." The knife block is now held in the upper end of the inclined grooves by the spring pressure. The drilling cable on which the tools are lowered is then hitched to the beam, the play of the jars being adjusted so that they strike on the downstroke but not on the upstroke. With the first stroke of the jars the knife punches a hole through the casing, and succeeding blows will cause the knife to cut a slit vertically down the pipe. The progress of the knife will be retarded on encountering a casing coupling but not stopped. A slight tension is

held on the pipe while the tool is in operation. When a coupling is split, the pipe can be readily pulled apart, although the coupling sometimes fails to spread enough to permit pulling without first driving down on the upper end of the column with the drive clamps and head. As the casing splitter is withdrawn, the knife block is forced down the inclined slots and away from the casing, compressing the mandrel against the spring. If necessary to effect withdrawal, the knife can readily be broken by driving up with the jars.

The casing splitter is commonly used in salvaging casing when a well is to be abandoned, and when the work involved in freeing an entire string of pipe would be too expensive. The tool may also be used for perforating pipe opposite an oil sand, though it is not so satisfactory for this purpose as a somewhat similar tool called a "casing perforator." Casing perforators are described on pages 408–412.

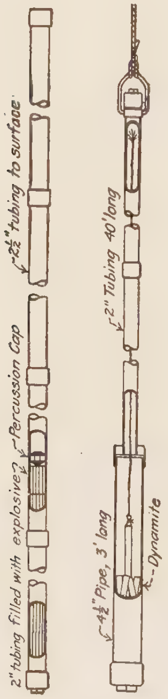
Use of Explosives in Parting Casing in the Well.—The simplest and cheapest method of parting a string of casing in the well is by the use of explosives. If a well is to be abandoned, the operator is anxious to salvage as much of the casing as possible at the lowest cost. An effort is first made to pull the casing. If it is frozen so that it cannot be readily pulled, explosives may be applied, parting the pipe a short distance above the shoe. If the casing still resists pulling, another shot may be fired some distance above the first and blasting continued at successively higher points until the pipe can be pulled. Another frequent use of explosives in parting casing is found in freeing a water string from a cement plug when the shut-off has been unsuccessful. The lower end of the pipe may be shot to pieces so that the upper can be withdrawn and a new shoe attached. The lower part of the hole must then be redrilled and a shut-off attempted at a lower horizon.

Either dynamite, blasting gelatin or nitroglycerin may be the explosive used, though blasting gelatin or ordinary stick dynamite is ordinarily preferred as a safer and more reliable type of explosive than nitroglycerin. The explosive is charged into a suitable container or "torpedo" and is detonated with a blasting cap of fulminate of mercury, fired either electrically, with a fuse or squib or by the impact of a "go-devil" dropped from the surface. Electrical firing is safest, but a fuse or squib may be used with security if care is taken to make certain that the charge is properly placed and timed. The risks involved in handling explosives are appreciated by most operators, and it is customary to employ someone skilled in the use of explosives when such work is done. Often it is done under contract by men who specialize in well shooting. The danger is not only to the workmen but to the well also, for a premature explosion at some point above the desired horizon will wreck the casing, perhaps causing caving of the walls and burial of the well equipment, in some cases even necessitating abandonment of the well.

If dynamite is to be used, it must be lowered on the sand line to the desired point in a container made of casing or tubing. From 20 to 40 sticks of 60 per cent dynamite are carefully packed into a piece of casing 4½ in. in diameter and 3 ft. long, with a coupling on each end and a plug in the lower coupling. In the top coupling a 4½- by 2-in. bushing is placed to connect with two joints (about 40 ft.) of 2-in. tubing, which contains the fuse. A plug is placed in the top of the tubing so that the entire container is water-tight. A small bail at the top provides a means of connecting with the sand line (see Fig. 140). A length of fuse is cut sufficient to allow ample time for lowering the explosive after lighting at the surface, and a detonating cap is crimped on one end and inserted in a stick of the explosive in the usual way. With the container charged with explosive and suspended in the well so that the top of the tubing is 2 or 3 ft. above the derrick floor, the squib is lowered through the tubing by means of the fuse until it rests upon the top of the explosive in the 4½-in. container. The fuse is then ignited, the plug screwed into the top of the tubing and the container with its charge is carefully lowered to the desired point in

the well. The explosive container and tubing will be shattered by the explosion, but the sand line will ordinarily be uninjured.

When it is desired to shatter a considerable length of casing, say, several hundred feet—as in shooting a section of cemented pipe—a string of 2½-in. tubing, plugged at top and bottom and as long as the section of pipe to be shattered, can be filled with explosive and detonated (see Fig. 140). In this case it might be preferable to



(*After T. Curtin in U. S. Bur. Mines, Bull. 182.*)

FIG. 140.—Illustrating use of tubing as dynamite container.

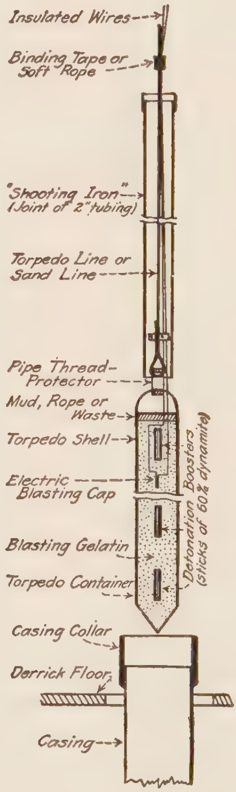


FIG. 141.—Illustrating manner of loading and lowering torpedo.

fire the charge by means of a squib dropped upon the charge from the surface (see page 422).

In firing electrically, the explosive should be placed in tubing or casing or in a torpedo shell, as described above, with an electric detonator on top of the charge (see Figs. 142 and 143). Two insulated copper wires connecting with the squib are carried through a water-tight joint in the plug, which encloses the top of the container, and are bound with cord or friction tape at intervals to the sand line on which the explosive is lowered. After the charge has reached the desired point in the well, the two wires are connected with a blasting machine or to a two-pole switch placed in the lighting circuit and the charge is fired. There is less danger of premature explosion when this method of firing is employed, and successful detonation of the charge is more certain than in firing by either of the other methods described above.

In the California fields,* most well shooting is done with blasting gelatin, which is less sensitive than 60 per cent dynamite and therefore safer to use in practice. The blasting gelatin is carefully tamped into a cylindrical torpedo shell made of No. 28 galvanized sheet iron, with a few sticks of 60 per cent dynamite scattered through the charge to insure complete detonation of the gelatin (see Fig. 141). Electrical firing is preferred, a special 150-grain fulminate of mercury cap being used for detonation. Generally more than one cap is used, in order to detonate the entire mass

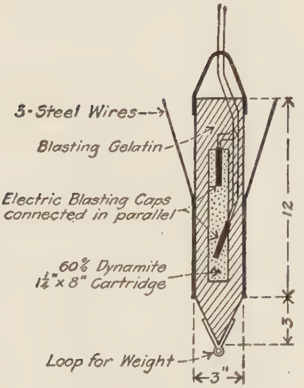


FIG. 142.—Hercules electric detonating squib.

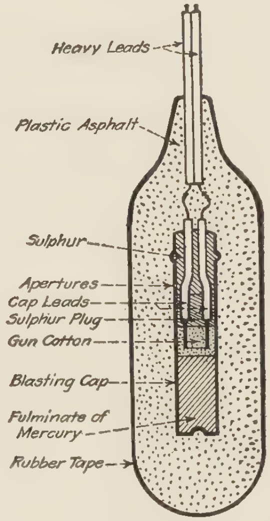


FIG. 143.—Allison electric detonating squib.

completely, one cap being used for every 3 lin. ft. of the length of the shell. The upper end of the torpedo should be closed with a pressure-resisting seal, to prevent compression of the gelatin, which, it is thought, may be the cause of premature explosions. A "shooting iron," consisting of a joint or two of 2- or 3-in. tubing, is suspended over the sand line, just above the torpedo, to prevent the line from being shot into a tangled mass by the explosion. The caps used are connected in parallel with the firing circuit and symmetrically placed throughout the charge. The torpedo is usually lowered on the sand line, which forms one wire of the circuit, while an insulated copper wire bound to the sand line at intervals completes the connection with the blasting machine or electric circuit at the surface. If there is oil in the well, there is a possibility of the electrical connection with the sand line becoming insulated, causing a mis-fire, and for this reason some well shooters prefer to use two separate wires for the electrical circuit instead of depending upon the sand line to form one lead. Before the charge is lowered, and before firing, the circuits should be tested with a sensitive galvanometer and a silver chloride cell. The latter does not produce sufficient current to fire the caps, but, as an added precaution, a suitable resistance is maintained in the circuit while testing.

Further description of the use of explosives in wells will be found in Chap. XI.

* GOLDMAN, F., and G. D. STEAD, Oil-well Shooting, a thesis prepared under the direction of the author, University of California, 1923.

RECOVERING STEEL AND HEMP CABLE

When the cable drilling tools are used, the drilling cable or sand line will occasionally break with the tools or the bailer in the well. If the break has occurred at some distance above the point of connection, the parted end will fall to the bottom in a twisted mass on top of the tools

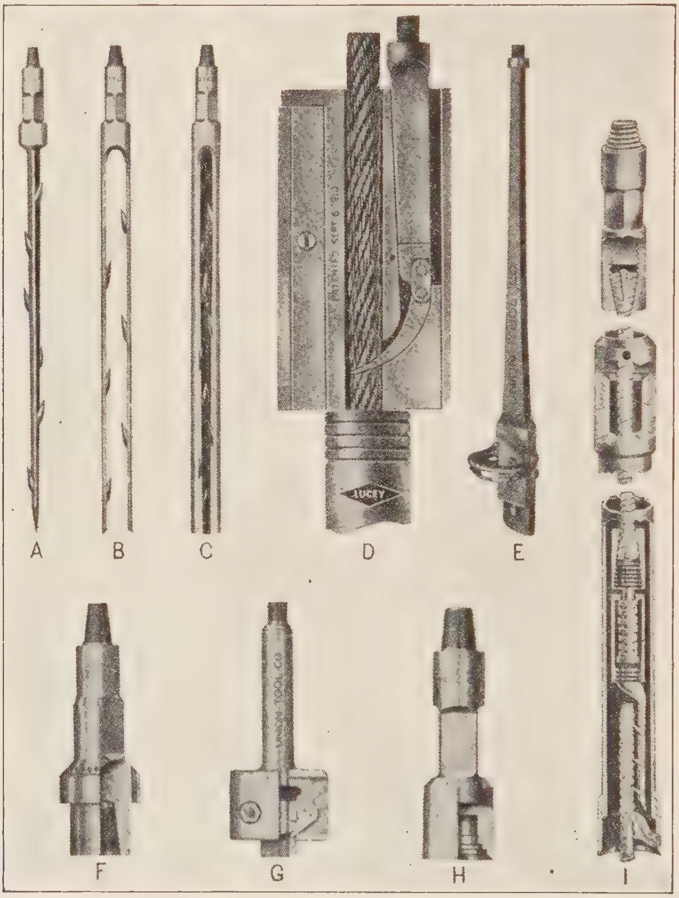


FIG. 144.—Tools for recovering drilling cable and sand line from the well.

A, rope spear; *B*, rope grab, two prong; *C*, rope grab, three prong; *D*, Spang wire-rope knife; *E* and *G*, other types of rope knives; *F*, rope spear wadder; *H*, blind rope chopper; *I*, Heeter's mouse trap.

or bailer and must be recovered with the aid of a rope grab or spear. Occasionally, too, the drilling tools or bailer will become lodged in the well, either as a result of the walls caving, or of the upper end of the string catching under the casing shoe. In such a case it may be necessary to cut the drilling cable or sand line in the well directly above the rope socket or bailer bail, so that other fishing tools may have ready access to the tools or bailer. For this purpose various types of rope

knives are used. The forms of rope grabs, spears and knives used will vary somewhat with the kind of rope to be recovered, that is, whether it is of manila hemp or steel wire.

Rope Grabs and Spears.—A group of representative rope grabs and spears are illustrated in Fig. 144. It will be noted that they consist of one or more prongs with a number of upturned, sharp-pointed "thorns" or spikes projecting from them. A pin joint at the top provides a means of connecting with a fishing string consisting of long-stroke jars, drill stem and rope socket. The tool is lowered and spudded up and down on the cable until the prongs and spikes take hold and the rope can be drawn to the surface. If the broken end of the cable is not long enough to reach to the surface, the hold of the spear is usually sufficient to support the tools or bailer so that it can also be withdrawn. The "mouse trap," illustrated in Fig. 144, serves a similar purpose. This tool is lowered on three joints of tubing.[5] A few feet of cable will always enter the lower end, the small hinged wickers take hold and, as the upper part of the tool is pulled up, the rope is drawn into the tubing. Sixty-five feet of cable can be removed with each run.

Rope Knives.—If the bailer or tools become lodged in the well and it becomes necessary to cut the drilling cable or sand line to permit of access being had by tools employed in loosening them, one of several types of rope knives may be used. These knives vary from simple V- or hook-shaped bars with sharpened edges, or chisel and shear-shaped "choppers" used on hemp cable, to the stronger and more elaborate wire-line knives which require the use of auxiliary jars and sinkers. The hemp knives and choppers are lowered with a sinker bar on the end of the sand line.

The resistant nature of steel wire cables requires a knife of greater strength and more positive manner of application. Such tools are usually lowered over the cable to be cut, and the knives are tripped or driven into cutting position on striking the rope socket or bailer bail. A common form (see Fig. 144*G*) has one or more "dogs" with sharpened edges, so pivoted that they remain in a vertical position as long as the tool is being lowered, but fall into horizontal cutting position and bear against the cable as soon as they are raised. Another type (see Fig. 144*E*) has a pivoted hollow disk, sharpened on the inner edge, which is held in horizontal position and free of the cable which passes through it, until tripped by contact with the rope socket or bailer. The disk-shaped knife then falls to an inclined position about the cable, and, on drawing the tool up, the rope is sheared off. Still another type (see Fig. 144*D*) is equipped with a curved knife on a steel mandrel, which is driven into cutting position with the aid of a sinker bar and a light pair of jars lowered on the sand line.

RECOVERING PARTS OF THE STRING OF CABLE DRILLING TOOLS

Such a variety of accidents are possible in the normal operation of the cable drilling tools that many different fishing tools are necessary if the operator hopes to be equipped for any contingency that may develop. Perhaps the most common fishing job that arises with cable tools results from unscrewing of a tool joint in the well. If the joints are not set up securely, or if the threads are defective, vibration of the tools while in operation may easily cause one of them to unscrew. Furthermore, unless the driller is skillful in recognizing the difference in the cable vibration after such an occurrence, the upper part of the string may be permitted to pound on the top of the detached portion until the ends become upset and the threads ruined. Breakage of various parts of the string of tools

will result in all or a part of the string becoming detached—the drilling cable may pull out of the rope socket, the tool joints may "jump a pin" or

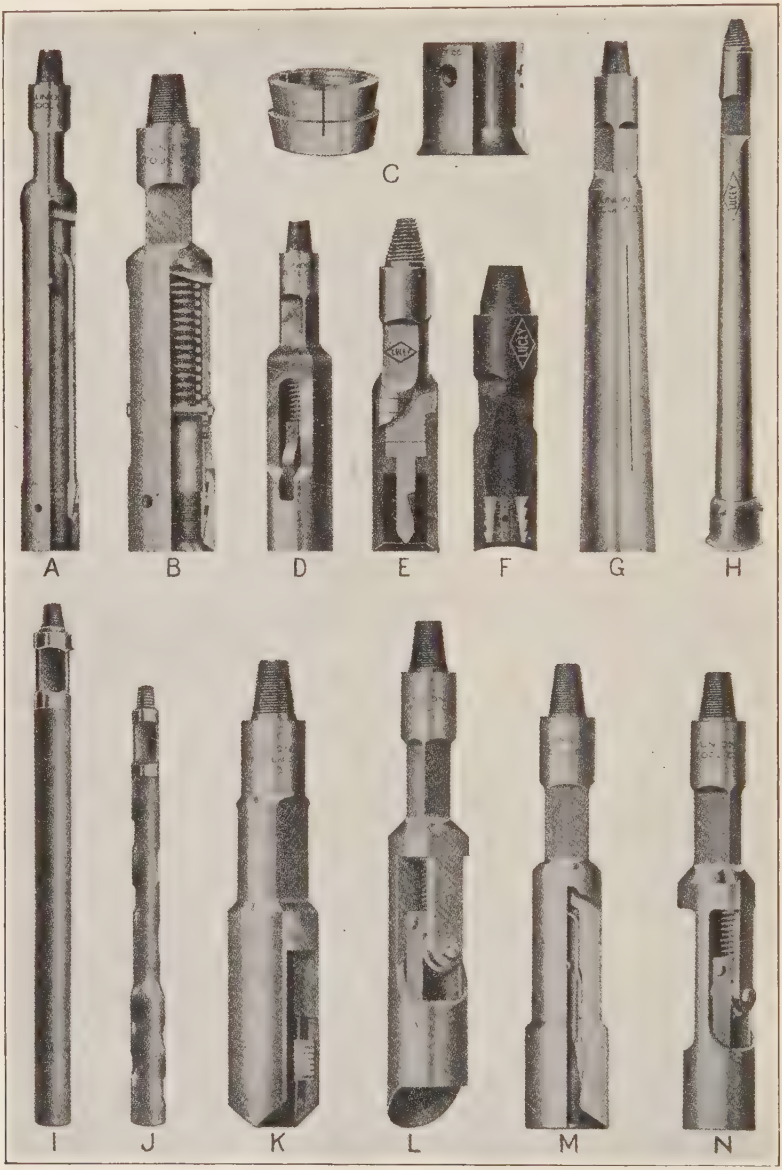


FIG. 145.—Types of sockets.

A, slip socket; *B*, combination socket; *C*, slips and bowl for combination socket; *D*, collar socket; *E*, rope socket, tongue socket; *F*, bulldog pin socket; *G*, horn socket; *H*, horn socket with bowl; *I*, round spud; *J*, corrugated friction socket; *K*, center jar socket; *L*, jar rein socket; *M*, jar tongue socket; *N*, side jar socket.

break off as a result of unequal pressure on the bit, or excessive strain from other causes. Steel will "crystallize" as a result of the continued

vibration and break at some weak cross section, such as the base of a pin joint or across a wrench square. Defective welds often open and pull apart. The jars sometimes break so that the two links pull apart. If the casing shoe is held too far off bottom, the upper end of the string of tools may fall to one side and get caught under the shoe. A cave of loose material from the walls may bury the tools. Under-reamer lugs frequently break or become loosened and fall to the bottom of the hole.

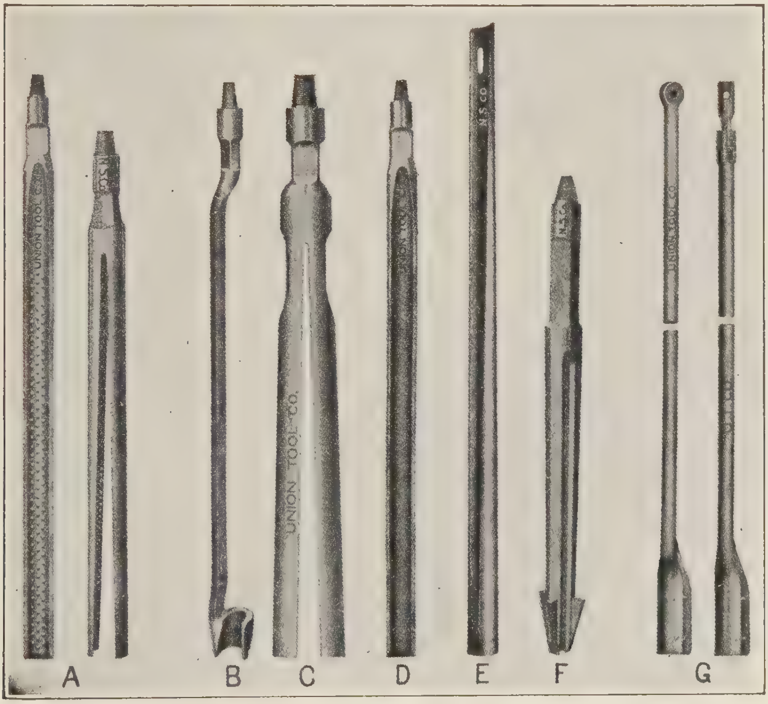


Fig. 146.—Tools for recovering parts of the cable drilling "string."

A, types of rasps; *B*, wall hook; *C*, hollow reamer; *D*, spud; *E*, whip stock; *F*, whip-stock grab; *G*, types of jar knockers.

Any one of these occurrences will necessitate interruption in normal drilling procedure while the detached part is recovered or the condition remedied.

Use of Various Sockets.—A variety of types of sockets have been designed for taking hold of the different parts of the string of cable tools, some of which are illustrated in Fig. 145. The "slip socket," the "combination socket" and the "collar socket" will pass over the end and take hold of any cylindrical object. Frequently they are equipped at the lower end with a conical bowl which serves to guide the upright end of the detached tool into the slips. A group of other tools, among them the "horn socket," the "round spud" and the "corrugated socket," serve a somewhat similar purpose but operate on a different principle. These tools are hollow and are driven down with the jars over the detached tool until a friction hold is taken. If the drilling cable has pulled out of the rope socket, a "tongue socket" may be used. This

consists of a pair of slips on a mandrel which is lowered into the hole in the center of the rope socket. A "pin socket" may be used to engage the tapered threads of an exposed pin joint, if a tool joint has become unscrewed and the threads are not damaged. For taking hold of the jar reins when they pull apart in the well, several special forms of sockets equipped with slips in different positions are available; thus, there are "center jar sockets," intended to pass between and catch both reins of the broken jars; there are "jar rein sockets," designed to take hold when one broken rein is longer than the other; the "jar tongue socket" and the "slide jar socket" are tools that pass over and grip the tongue of the jars. Of these different forms of sockets, the combination socket, equipped with slips actuated by the pressure of a powerful spring, is of greatest utility and is most positive and reliable in action. However, the ordinary type of slip socket, in which the slips are placed on the ends of a U-shaped stirrup, is cheaper and for many purposes equally reliable.

Use of Rasps.—If the end of the detached tool has been upset and battered by pounding of the tools, it may be necessary to remove the ragged or upset edges or corners with the aid of a rasp. This is nothing more than a large file which is suspended on a drill stem and spudded up and down about the top of the detached tool. Two forms are available: one, the so-called "side rasp," which is a single semicircular bar, curved to the diameter of the tool on which it is to work, and the other a "two-wing rasp," designed to pass over the end of the tool and work on two sides at once (see Fig. 146).

Use of the Twist Drill and Twist-drill Spear.—When the detached object is so large or has been so badly upset that it fills the hole and prevents operation of a rasp or other fishing tool, a hole may be drilled vertically into it with a substantial twist drill which is rotated on tubing. After the hole is drilled, a twist-drill spear may be lowered into it, a hold taken and, unless the friction is too great, the detached tool or object withdrawn. The spear used in such a small hole is necessarily weak and is not intended for lifting heavy objects or for cases which require heavy pulling.

Use of the Wall Hook or Bit Hook.—If a drilling bit becomes detached from the rest of the string in the well, it often leans against one side of the hole so that the upper end is not accessible to fishing tools which must pass over it to operate successfully. For such a situation, the wall hook or bit hook is used. This is a tool (see Fig. 146) consisting of a long bar, offset from its point of support, with a semicircular hook on the lower end, of proper size to slip around the tool under the collar, straightening it in the hole and supporting it while it is being withdrawn. It is equipped with a pin joint at the top and can be lowered on a string of sucker rods or tubing, and functions when turned in the hole after reaching the proper depth.

Loosening Stuck Tools.—If the tools become fast in the hole as a result of caving of the walls, or by "heaving" of sand from the bottom, it is generally necessary to remove or loosen the material over and about them before they can be withdrawn. For this purpose, either a hollow reamer, a "spud," or a "whip stock" may be used (see Fig. 146). The hollow reamer is merely a cylindrical tube split into two wings and dressed to a sharpened edge at the bottom, which is spudded up and down on the tools in the well. The two wings spring apart after passing the casing shoe, and the inner diameter is such that the reamer passes over the detached tools in the well and works on the material about them. The semicylindrical spud is used for a similar purpose. The whip stock is lowered on top of a lost string of tools when it is desired to drill by them. The beveled face of the whip stock causes the working tools to glance off to one side of the detached string. Tools may be sidetracked in this way, or they may be caused to fall into a hole drilled below them, in the hope that they will assume a more accessible position than they formerly occupied. The "whip-stock grab" is a fishing tool that is used in removing the whip stock from the well after the work is completed.

If the drilling tools are lowered without a pair of jars in the string and become embedded in the hole, it may be impossible to release them by a direct pull on the drilling cable. In such a case a "jar knocker" (see Fig. 146) is often called into service. This is a heavy bar, from 8 to 24 ft. long, which is lowered into the well on the sand line with its lower end encircling the drilling cable. The drilling cable is put under tension and the jar knocker is repeatedly raised 20 or 30 ft. and dropped on the rope socket until the combined jar and pull releases the tools. The jar knocker may also be applied in releasing the links of the jars, if for any reason they should become locked while the tools are in the well.

Use of Milling Tools.—When a pin is broken from a tool in the well, it is occasionally necessary to cut a new pin on the broken end to aid in its removal. A milling tool designed for this purpose is lowered on 2-in. tubing and revolved until the new pin is formed. A milling wheel is attached to the tubing and revolved by a rope drive from the bull wheels. A part of the weight of the tubing is sustained by a special milling jack which permits of rotation of the tubing and close adjustment of the rate of feed. Milling tools of somewhat different design are also available for cutting through casing (see Fig. 147).

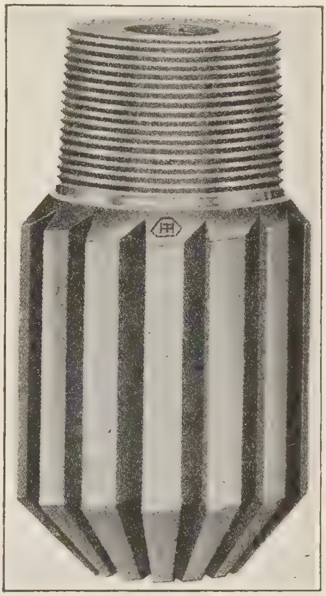


Fig. 147.—Hughes milling tool for cutting through and side-tracking casing.

RECOVERING A DETACHED BAILER

While no very great strain is ordinarily placed upon the bailer or its supporting cable, the sand line, it will occasionally become fast in the hole so that it cannot be removed without breaking the sand line. Caving of the walls or heaving sand from the bottom may bury the bailer completely so that it cannot be withdrawn. Again, the sand line may break as a result of wear, or it may become unfastened from the bailer bail, or the bail may pull out from the top of the bailer. In such accidents one or another of the tools described in connection with casing fishing jobs or cable-tool fishing jobs may be called upon, or a special tool called a "boot jack," or "latch jack," may be of service.

If the bailer cannot be pulled and the sand line is still intact and securely attached to it, a rope knife should be lowered and the line cut at the bail. The latch jack (see Fig. 148) may then be lowered on a fishing string with long-stroke jars, a stem and a rope socket, on the drilling cable. The latch jack is a fork-shaped tool, often made from the upper half of an old set of jars, with a small bar or latch pivoted on a pin set in one of the two reins. As this instrument is lowered, the two reins pass, one on either side of the bailer bail, lifting up the latch on its pivot. When the bail passes the latch, the latter falls back into horizontal posi-

tion and later engages the bail when drawn up. The tool is substantial enough to stand heavy pulling and the jars provide a powerful upward blow which soon loosens the bailer if the bail does not pull out. In the latter event, a casing spear or a bell socket may be called into service. A tool designed especially for recovering detached bailers is called a "bailer grab" (see Fig. 148). It contains one or two slips actuated by a powerful spring and passes over the outside of the cylindrical portion of

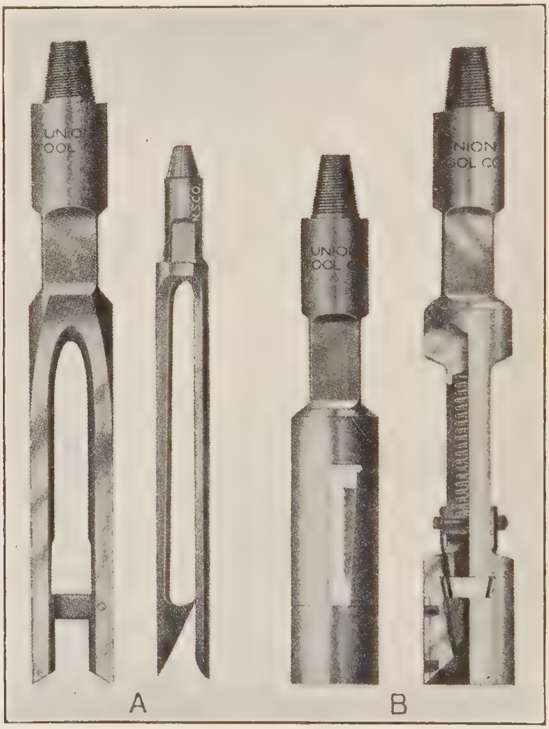


Fig. 148.—Fishing tools for recovering bailers.
A, boot or latch jack; *B*, bailer grabs.

the bailer. If all of the methods suggested above fail, the bailer may be drilled up with the tools and sidetracked.

RECOVERING SMALL IRREGULARLY SHAPED OBJECTS

Recovery of small irregularly shaped objects, such as under-reamer lugs, slips or parts of fishing tools that break in service, is accomplished with the aid of either an "alligator grab" or a "devil's pitchfork." The manner in which these tools operate will be apparent from an inspection of the illustrations given in Fig. 149.

Electromagnetic Fishing Tools

Electromagnets have been employed in recovering small or relatively light steel objects from wells, and some models, recently perfected, are

sufficiently powerful to lift heavy drilling tools. In order that it may develop maximum lifting force and not stick to the casing as it is withdrawn, a successful electromagnetic fishing tool must be so designed as to concentrate the magnetic force entirely on the lower end where it makes contact with the object to be retrieved. It is lowered into the well on a steel cable the core of which carries insulated wires through which the current necessary in the operation of the magnet is conducted. A service

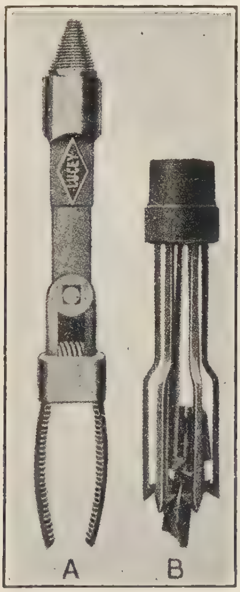


FIG. 149.—Fishing tools for recovering small irregularly shaped objects.
A, alligator grab; *B*, devil's pitchfork.

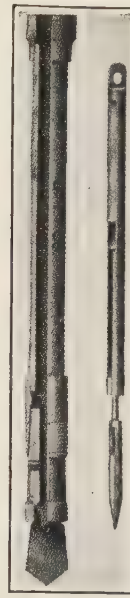


FIG. 150.—Wash-down spear with mandrel and jar.

truck used in conjunction with the tool carries a hoisting drum on which the special conducting cable is reeled and a motor-generator set which furnishes direct current of suitable voltage for operation of the magnet. An electromagnetic fishing outfit of this type used in the California and Texas oil fields is capable of lifting loads of 1,000 lb. or more and yet may be operated through 8¼-in. casing. Such a tool is quicker and more universal in its application than others which depend upon accurately gaged slips and which often fail to work because the detached tool is in an inaccessible position.

RECOVERING FRACTURED ROTARY DRILL STEM

The most frequent type of fishing job in rotary drilling is that occasioned by twisting off of the drill stem. Such a fracture usually occurs near the lower end of the stem. The fracture may consist of a simple shearing of the pipe, or failure may occur at a tool joint. In some cases

the "back lash" of the upper portion of the column of pipe, after the stem breaks, will cause a second fracture at some point above the first so that the pipe is in three pieces in the well.

The overshot (see Fig. 134) is the favorite tool for recovering drill stem twisted off in this way; but if mud has settled about the stem, it may be necessary to use a "wash-down spear," which is a special form of trip casing spear equipped with a diamond-pointed bit on the lower end and with openings through it for passage of the circulating fluid (see Fig. 150). It is lowered on a column of drill pipe of the same size as that detached in the well. The diamond bit, aided by the pump circulation, quickly forces its way through the accumulated mud and enters the broken stem until the slips take hold, after which the pipe can usually be withdrawn.

If the detached section of drill pipe cannot be pulled, the spear can sometimes be recovered by rotating the drill pipe on which it is lowered. Or, if the fishing string has been tightly made up, some of the lost pipe may be unscrewed by "backing up" or turning the fishing string at the surface in the hope of unscrewing one of the tool joints in the detached column of pipe.

In many fishing operations, as in recovering a section of rotary drill pipe after a twist-off, it will be somewhat uncertain whether or not the "fish" has been engaged by the tool used. In such cases, it is often convenient to use a weight indicator on the hoisting line (see p. 221). This device makes it possible for the driller to detect the slight difference in weight of the fishing string after the tool has taken hold.

Often mud and drill cuttings settle about the parted section of pipe so that it cannot readily be withdrawn after the overshot has taken hold. The lip of the overshot may be pointed to assist in "washing down" over pipe buried in sediment. The Baash-Ross overshot is equipped with a packing ring which, on lifting the fishing string after the tool has taken hold below a tool joint or coupling, closes the annular space between the fishing string and the parted drill pipe or casing. Circulation may then be established down, through and up, and about the outside of the parted pipe, thus assisting in freeing it from the accumulated detrital material.

If the parted drill stem cannot be recovered with either the overshot or the wash-down spear, it may be possible to unscrew a part of it in the well and remove it in sections. For this purpose, a string of pipe equipped with left-hand threads is made up, and a hold taken on the detached pipe, either with a spear or with a left-hand-threaded pipe tap or die nipple. The fishing string is then rotated counterclockwise, which tightens the left-hand threads but unscrews the right-hand threads of the detached stem. There is more or less uncertainty as to just where the detached column will unscrew, but three or four joints of pipe can often be recovered with each run.

The Houston Engineers' reversing tool may be conveniently used in connection with left-hand taps or dies in "backing off" parted casing or drill pipe which cannot be pulled from the hole. This device, connected in a string of right-hand drill pipe or tubing, imparts a left-hand motion to the tap or die. When the tool has taken hold, the parted section of pipe is unscrewed at some collar or tool joint below, after which it is possible to remove the portion above the uncoupled joint.

For cutting off frozen drill pipe, it is necessary to use a cutting tool that operates from the outside rather than the inside. The Baash-Ross drill-pipe cutter is of this type. It is lowered to the desired point on a string of pipe that telescopes over the column of parted drill pipe. On lifting the tool, an overshot takes hold below a collar or tool joint. Strain is then taken and the fishing string rotated, which forces the cutters against the drill pipe. After the pipe has been severed, that portion above the overshot is withdrawn with the fishing string.

When rotary tools are in use, the ordinary telescoping, link type of fishing jars may be unsuitable. In this case, the Kammerdiner rotary jar may be used. This tool is connected in the fishing string near the lower end. When the fishing tool has taken hold, the drill pipe or tubing on which it is lowered is turned one full turn to the left and then to the right three turns, when a threaded section of the tool is disengaged, causing the fishing string to be jerked upward under the tension provided, thus delivering a powerful upward jerk to the "fish."

When a section of detached drill pipe or casing or tool has fallen over to one side of the axis of the well, or into a cavity which may have formed about the well as a result of a cave, special forms of wall hooks or "knuckles" may be used in conjunction with other appropriate fishing tools. One variety of tool of this class, manufactured by the Specialty Oil Tool Company, designed for use with rotary tools, is deflected from the axis of the well to one side at the will of the operator, by application of hydraulic pressure developed through the drill pipe. On rotating slowly, the tool then engages the lost pipe or tool and draws it back into the axis of the well. The "Sotco" hydraulic wall hook is also equipped with slips which grip casing or drill pipe after it has been straightened in the hole so that it may be lifted to the surface with the fishing string. Special types of eccentric sockets and grabs are also available for off-center fishing operations.

If the lost drill pipe cannot be recovered by either of the methods suggested above, a whip stock is lowered into the hole and the parted section is sidetracked. If the upper end of the detached stem happens to be up inside of the well casing, a hole may be cut through the casing for the passage of the drilling bit and stem with the aid of a milling tool, after the whip stock is in position.

A means of attaching the drill collar and rotary bit to the drill stem in such a way that they are not detached from the stem if a twist-off occurs near the lower end, is said to greatly reduce the number of rotary fishing jobs. The Baughner device, named after the inventor, J. D. Baughner, a California well driller, ties the four bottom joints of drill stem, the drill collar and bit to the nearest tool joint above[5]. This is accomplished by means of a wire cable 80 ft. long, babbitted into a rope socket at each end, the sockets being shouldered and resting on the pin of the drill collar at the lower end and at the upper end on the pin of the tool joint. Between the rope sockets and the pins, slotted washers are placed, which permit passage of the circulating fluid. The cable rotates with the stem and in no way prevents circulation of the mud fluid. Should the drill collar or either of the lower joints break, the rope keeps them suspended so that they can be withdrawn with the upper part of the drill stem. On one well drilled in California this device prevented 24 out of 27 fishing jobs due to twist-offs.

USE OF ACIDS IN FISHING OPERATIONS

Occasionally, in difficult fishing jobs near the bottom of the hole, resort may be had to the use of acids capable of dissolving the metal or the tools or the minerals composing the wall rocks or detrital material settled about the lost tool or pipe. The appropriate acid to use will depend upon the conditions presented and the objective to be gained, but hydrochloric, nitric, sulphuric and hydrofluoric acids comprise the list from which a choice must ordinarily be made. Limestones are easily soluble in hydrochloric acid, silicates in hydrofluoric acid. Nitric acid and sulphuric acid, in certain concentrations, are effective in dissolving iron and steel. While the lost tool will not ordinarily be entirely dis-

solved by acid treatment, it may be so reduced in size that it can be more readily freed from the walls of the well. The acid, brought to the well in carboys, is lowered to the bottom of the hole in a dump bailer (see page 356).

DETERMINING THE POSITION AND CONDITION OF A DETACHED TOOL IN THE WELL

Before selecting a fishing tool to recover a detached tool in the well, it is often essential to determine its position in the hole as well as the condition, form and exact size of the upper end. For this purpose, an "impression block" is prepared.[3] This consists of a round piece of wood about 2 ft. long, which is of such diameter that it can be readily lowered through the hole, and concave at the lower end. A few nails projecting from the concave end serve to hold a mass of soft soap. The impression block is lowered into the hole, either on the bottom of the bailer or attached to the lower link of the jars by a pin joint cut on its upper end, until it rests upon the top of the detached tool. When withdrawn, the indentations in the soap indicate fairly well the position, form and size of the upper end of the tool in the well and enable the driller to select a fishing tool to recover it.

It has been suggested that a special camera might be devised, with an electric lighting device and electric control, which could be lowered into the well and a photograph made of parted casing, a detached tool or any other obstruction. Such cameras are used in photographing the position of magnetic needles in making surveys of wells but seem scarcely applicable under the conditions pertaining in fishing operations. The well fluid and accumulated sediment would generally obscure the object even if a workable camera could be devised.

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CHAPTER X

OIL-FIELD HYDROLOGY; EXCLUSION OF WATER FROM OIL AND GAS WELLS

Occurrence of Water in Sedimentary Strata.—Everywhere at a variable distance below the earth's surface, the rocks are supposed to be saturated with water. The upper surface of this body of ground water, called the "water table," is irregular in contour but roughly parallels the configuration of the earth's surface. In most regions it is found near the surface, but in arid regions it may be found at a depth of several hundred feet. Below the water table, the rocks are assumed to be saturated with water until a temperature is reached at which water cannot exist. This again, however, is a more or less indefinite depth and is conditioned by many irregularities. To the general assumptions just given, there might be cited numerous exceptions of mines the lower levels of which, far below the water table, are almost barren of water.

While all rocks below the water table are known to contain more or less water, the degree of saturation and the hydrostatic pressure are widely variable and circulation of ground waters is confined largely to the more porous beds. Sandy strata, which offer relatively large pore space and freedom for the passage of fluids, are often completely saturated with water under high pressure, and are called "water sands," to distinguish them from rocks containing small quantities of low-pressure waters. It is probable, however, that even the so-called "dry sands" contain some water, and that they are only relatively dry. Clay, which is not usually thought of as a source of water, will often contain more water than highly porous sand, but it does not yield its water so readily.

Many drillers believe that it is possible to distinguish between "water sands" and "dry sands" or "oil sands" by the texture or form of the sand grains. It is claimed that the grains of a water sand are sharper or more angular, or that they are smaller. Some believe that grains of mica are characteristic of water sand but are not ordinarily present in oil sand. While such characteristics are of value in correlating sands as between near-by wells, it must be recognized that the rock fluids are of secondary occurrence and cannot be in any sense related to the lithological properties of the sand, or to the minerals forming the grains. A water sand is any sand that contains water which it freely gives up. A sand which contains oil is an oil sand for present purposes, though at a former

period it may have been a water sand. Conversely, an oil sand, by exhaustion of its oil content, may later become waterlogged.

Pressure within water-saturated sand will in general increase with depth below the water table. This is due primarily to the hydrostatic head of the superimposed column of fluid, perhaps, also, to "rock pressure." There are many apparent exceptions to this general statement. Waters in different beds, separated from each other only by a thin parting of impervious clay or shale, may appear to be under quite different hydrostatic heads; however, this difference is probably more apparent than real. It must be remembered that the flow of water into a well and the pressure conditions developed within it are in most cases but an expression of the permeability of the formation. Strata which offer great resistance to movement of fluids will yield their contained water too slowly to reach static pressure equilibrium within a short period of time and will appear to be of lower pressure than other more permeable beds which yield their water freely and quickly reach pressure equilibrium.

Much of the water present in the upper horizons of the earth's crust is replenished seasonally through outcropping porous beds by percolating surface waters, and there is necessarily considerable lateral and vertical movement of these ground waters in adjusting the differences in pressure which naturally result. Much of the water present in rocks, however, particularly in the deeper sedimentary rocks, is connate water occluded within the rock mass during sedimentation. This water, too, may be forced to migrate by cementation, consolidation of sediments and the accumulating weight of overlying strata, but it is in many cases held practically trapped within the basins of folded structures.

Identification of Water Sands in Drilling.—In the usual processes of drilling, it is often a difficult matter to determine the pressure on a water sand, or the rate at which water may flow from it. In the "standard" or cable-tool method of drilling, it is customary to maintain a certain depth of water in the hole, which may be sufficient to prevent low-pressure water from entering the well. For example, a 1,000-ft. column of water exerts a hydrostatic pressure of 434 lb. at the bottom of the well, and, if the head on a water sand is less than this, no water will enter the well from it. On the other hand, if the differential pressure is sufficiently great, water may flow from the well into the sand. If the fluid level in the well sinks as a new sand is encountered, it is logged as a "dry" sand, but this usually means merely that it contains water under relatively lower pressure than that produced by the static head of fluid in the well, and that the permeability is such as to permit of rapid migration from the well into the formation. If, on the other hand, the fluid level rises when a new stratum is penetrated, it becomes evident that water is flowing into the well from the new sand and that the fluid in it must be under greater pressure than that represented by the column

of fluid in the well; also, that its permeability is sufficiently great to permit of rapid flow of fluids through it. A study of fluid levels during the process of drilling will thus give valuable data on possible sources of water which may prove troublesome during a later period. If it is safe to do so, the fluid in the well should be bailed down whenever a new sand is encountered until the nature and pressure of its fluid content can be determined. At such times, samples of the fluid should also be gathered for analysis and future comparison.

In rotary drilling, on account of the mudding of the walls and the necessity for continual circulation of fluid, it is a far more difficult problem to estimate the water-yielding capacity of the formations penetrated. However, if a bed is porous and under low pressure, it will probably absorb fluid from the circulating system so that the fluid level of the mud pit falls and additional water has to be added. This should be accompanied by a decrease in pump pressure necessary to maintain circulation. If, on the other hand, a sand contains water under high pressure, the difference between its upward pressure and that of the column of circulating fluid may be so small that it is not shown by the pump gage and there may be nothing to warn the driller of the presence of a high-pressure water sand that may later cause trouble unless properly cased off. It is obviously impractical to bail down a rotary-drilled well frequently in order to obtain samples of rock fluids, or to make tests of fluid pressure. Recently, mechanical formation samplers have been developed, which are designed to isolate a small section of the well and to so control the pressure conditions within it as to permit of securing an uncontaminated sample of the rock fluids (see pages 405–406).

Relation of Water to the Oil.—Water sands may be found both above and below and occasionally within the oil zone and are referred to respectively as "top water," "bottom water" and "intermediate water." The water which underlies the oil in the lower horizons of an oil stratum is commonly called "edge water." In horizontal or low-dipping strata, the lower portion of a thick oil-bearing stratum may contain water, the oil apparently floating on top of the water. It is probable, however, that in many supposed cases of this sort, there is an impervious bed separating the two, so thin perhaps, that it has not been logged in the process of drilling.

Chemical Constitution of Ground Waters Associated with Oil Deposits.—In strata to which surface waters have access, the water is characteristically fresh, but in deeper horizons where movement is sluggish the waters may acquire considerable percentages of dissolved solids from the surrounding rocks. Connate waters occluded within marine sediments at the time of sedimentation were initially saline and in many cases have remained so throughout subsequent geologic ages. Such waters, by interaction of different dissolved salts, are often the cause of

secondary cementation and replacement in porous rocks to which they have access.

The universal association of brine with petroleum deposits is a matter of common knowledge and some geologists believe that commercial deposits are to be found only below the fresh-water level. Oil-field ground waters frequently contain several times as much dissolved salt as ordinary sea water. It is reasonable to assume that appreciable changes in the chemical composition of these connate waters have occurred throughout long periods of geologic time.

There are marked differences in the concentration of dissolved salts and in the nature of the salts present in oil-field brines. The waters of different strata are usually distinctive and often differ markedly from each other in chemical constitution and reactivity. The dissolved salts commonly present in ground waters are primarily the chlorides, sulphates, nitrates, carbonates and bicarbonates of the alkalies and alkaline earths (sodium, potassium, magnesium, calcium, barium and lithium). Iron, alumina and silica are often present in small amounts and occasionally hydrogen sulphide or sulphur dioxide will be found in solution. The preponderance of one or another of these elements or radicals is often a reliable characteristic of the water in a particular stratum, and the different strata in a given locality may in many cases be readily identified and correlated from well to well by making analyses of their contained waters and noting common characteristics. For example, a persistent top water overlying the oil measures in the Coalinga field of California contains dissolved hydrogen sulphide and is so well known throughout the district by this characteristic that it is often used as a "marker" horizon in making correlations from one well to another.

In some fields the dissolved salts present in ground waters appear to bear a certain relationship to the proximity of petroleum. It is found in some oil fields, for example, that the waters immediately associated with the oil measures are notably lacking in sulphates but are often high in carbonates. There is some evidence to show that this may be attributed to the reducing effect of decomposing organic matter from which petroleum is formed; or it may result from slow reduction of the sulphates by prolonged contact of ground waters with petroleum itself under certain conditions of pressure and temperature. Reduction of the sulphate to sulphide is accompanied by the formation of carbonate, and the proportion of carbonate is thus abnormally increased. An unstable sulphide of iron may also be formed as a result of this reaction, imparting to shales and clays a characteristic blue color. The presence of barium and strontium may explain the absence of sulphates in some cases. It is also known that certain anaërobic bacteria, which are apparently able to live in petroleum, have the ability to convert sulphates into sulphides. In the Appalachian fields concentrated chloride waters associated with the

oil and gas contain noteworthy amounts of calcium. The waters are characteristically lacking in sulphates but usually also lack carbonates. In some of the San Joaquin Valley fields of California the surface waters contain sulphates, but in the sands immediately above the oil zone sulphates practically disappear and are replaced by carbonates. Edge waters and bottom waters in this region are high in chlorides. So persistent are these characteristics that in certain fields operators find it advantageous to make chemical analyses of all waters encountered in the drilling of wells and are able to predict, in some measure, the position and proximity of the source of the sample with respect to the oil zone.

It is a matter of common belief that petroleums suffer an increase in density by contact with ground waters. This may be explained from the chemical point of view as a result of the reduction of dissolved sulphates in the water in contact with the oil. As a product of this reaction, hydrogen sulphide is formed and the carbon formerly linked with this hydrogen forms carbon dioxide or carbonate. It is a well-established fact that oil in contact with sulphides will increase its density and viscosity by the formation of complex hydrocarbon-sulphur compounds.*

Temperature undoubtedly plays an important rôle in influencing the solution capacity of ground waters for soluble salts. Temperature increases in a constant ratio with depth, and temperatures ranging between 100 and 200°F. are not uncommon in oil-field ground waters produced from a depth of 3,000 to 8,000 ft. Waters which become saturated with a soluble salt at such temperatures may, on subsequent cooling, precipitate cementing material between the grains of porous rocks to which they have access. Chemical interaction between dissolved salts as a result of contact between different ground waters has a similar effect. It is thought that the accumulation of large quantities of salt from waters in oil and gas wells, and the sealing of the pores of productive oil and gas sands by deposition of salt, also result from such reactions, though in some cases it is probably due to the evaporative effect of natural gas on water within the well, evaporation of the water causing concentration and eventual supersaturation of the well fluid accompanied by deposition of salt.

Effects of Water Incursion in Oil Sands.—Accumulated water in the well has a marked influence on the rate at which oil may enter from an oil sand in the bottom. Oil flows into a well by virtue of the gas or hydrostatic pressure operative upon it. If the oil or gas pressure is opposed by the hydrostatic pressure of water accumulated within the well, it is obvious that less oil will enter. Frequently the water pressure will be so great that no oil enters, and occasionally the direction of flow may be reversed, water entering the oil sand from the well.

* Rogers, G. S., Relation of Sulphur to Variation in the Gravity of California Petroleum, *Trans.*, Am. Inst. Mining Met. Eng., vol. 57, pp. 989–1009, 1917.

If water enters an oil-producing stratum from a well penetrating it, the oil will be forced away from the vicinity of the well. Furthermore, water entering an oil sand in this way apparently has the effect of altering the properties of the sand so that it does not yield readily to the passage of oil through it, even if at some later time water is excluded from the well. If large volumes of water are permitted to enter, they may migrate through the oil sands, influencing the production of wells at a considerable distance from the point at which they enter. Large areas may thus become flooded to such an extent that profitable production of oil from them becomes impossible.

Aside from its influence on oil production, the presence of water in the oil produced by a well increases the cost of operation, often necessitating the pumping of large volumes of worthless fluid, which must be separated from the oil at additional expense after it reaches the surface. Water-oil mixtures in the well sometimes form emulsions from which the oil may only be extracted with great difficulty and expense.

Because of the difficulties that result from the presence of water in oil wells, it should be excluded by suitable means. The necessity for water exclusion is one that is well recognized by oil producers, and the methods involved in accomplishing it have received a great deal of attention, particularly in certain fields where the menace of water incursion has become a problem of vital importance.

METHODS OF EXCLUDING WATER FROM WELLS

It has been shown that water entering an oil well may have its source in water sands located either above or below the oil zone, and that in some cases it may originate within the oil sands themselves as edge water; or it may be present as an "intermediate water" between two oil sands. The eventual encroachment of edge water into a well is unavoidable, and by present methods it is impracticable to exclude intermediate water if we would produce from two or more oil strata in the same well simultaneously; but the exclusion of extraneous top and bottom waters is readily accomplished by any of several methods. In the case of bottom water, in wells drilled to too great a depth, exclusion methods involve the placing of plugs which effectively seal off the lower portion of the well below the productive zone, while in the exclusion of top water it is necessary to seal off the space below the source of the water, between the walls of the well and a water-tight casing. Plugging off bottom water is relatively simple, but the effective and permanent exclusion of top water offers a problem that has taxed the ingenuity of oil producers to the utmost. Most of the flooding of oil sands that has resulted in many of our older fields has been due to ineffective methods of top-water exclusion.

Exclusion of Top Waters

Use of Packers.—Early methods of excluding top water involved the use of various forms of packers between the casing and the walls of the well. Bags of dry seeds or cereals were sometimes lowered into the well and manipulated until they passed under the casing shoe and up behind the casing above the shoe. On contact with water these materials expand and close the space about the pipe so that the descent of the

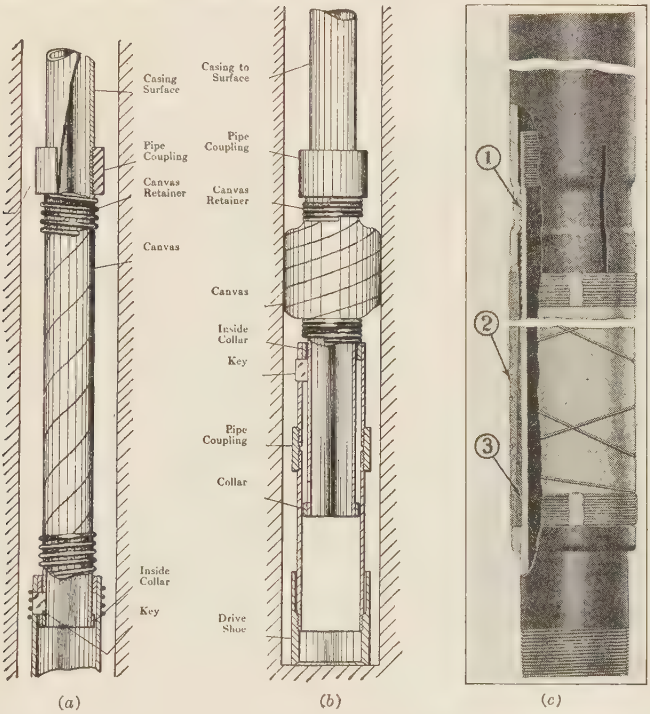


Fig. 151.—Types of canvas packers.

Lucey canvas packer, (*a*) before setting, (*b*) after setting; (*c*) Layne and Bowler canvas packer with lead cone, (1) threaded sleeve for setting, (2) canvas and (3) lead cone.

water is checked. Packers made of loosely wrapped canvas or hemp rope, placed on the outside of the pipe before lowering into the well, may be compressed into a shorter length, causing increase in diameter by proper manipulation of the pipe (see Fig. 151). Mechanical packers, designed to expand a rubber cylinder against the walls of the well under the influence of the weight of the casing, or by rotating the casing, are available and may be effectively used in excluding water under favorable conditions. All packers are constructed of materials which can scarcely be regarded as permanent in the sense that they will function effectively throughout the life of the well, and permanent water exclusion is necessary inasmuch as continued oil production is contingent upon it. Ordi-

narily it will not be possible to replace the packer at such times as it may cease to be effective since it is usually difficult to withdraw the casings from a well after the walls have had time to settle about them. Because of the temporary nature of packers, and the difficulty and uncertainty of setting them properly, they are seldom used for permanent exclusion of top water.

Mechanical packers are widely used for water exclusion in the older oil fields of the eastern United States, where the wells are of small capacity and relatively shallow, where the wall-rocks are firm and where the water problem is not a matter of such vital importance as in many of the western fields. A variety of different types of packers are available,

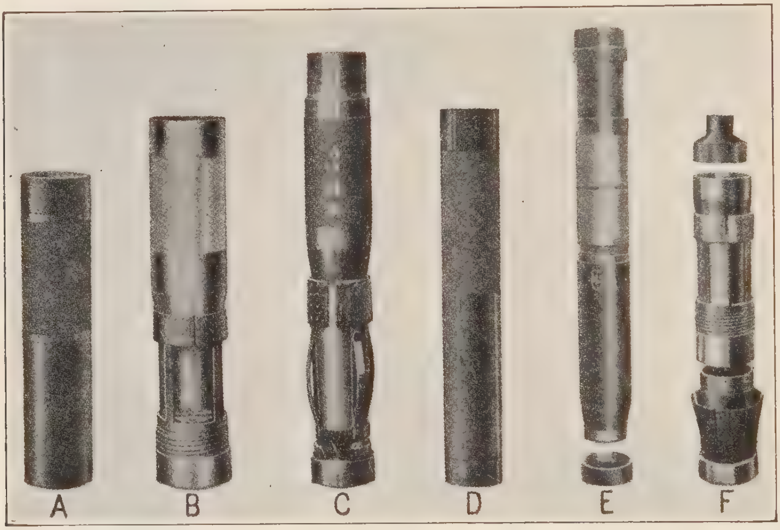


FIG. 152.—Types of packers.

A, bottom-hole packer; *B*, disk wall packer; *C*, hook wall packer; *D*, anchor packer; *E*, Robinson screw-down packer; *F*, cave packer.

designed for use under different conditions. All mechanical packers operate by expanding a hollow cylinder of rubber, lead, canvas or burlap at the desired point in the well, either by compression from the ends against a tapered metal sleeve, or by rotation of screw devices. They are lowered and manipulated on either casing or tubing and may be used to seal off the space between two strings of pipe or between the pipe and the walls of the well. Rubber packers range from 3 to 8 ft. in length, the rubber sleeve varying from 1 to 3 ft. in length. Canvas packers are commonly about 8 ft. long, with a canvas or burlap sleeve 3 ft. in length, though special packers of this type may be secured which are as long as 20 ft., with an 8-ft. sleeve of canvas or burlap.

Bottom-hole packers (see Fig. 152) are used on the lower end of a string of pipe to close the space between the pipe and the walls of the well. The packer is held in its extended position by copper rivets through the conical metal sleeves, but these

are sheared, permitting the sleeves to telescope and expand the rubber cylinder when the full weight of the pipe is allowed to rest on bottom. The lower end of such a packer is equipped with a substantial reinforcing shoe, while the upper sleeve is threaded to connect with the casing. The rubber cylinder fits snugly over the top or inside sleeve and is about ⅜ in. smaller in diameter than the hole it is designed to close when expanded.

Wall packers are used to close the space between two strings of pipe, or between the pipe and the walls of the well at some point above bottom. They are of several forms, the better known types being the disk wall packer, the hook wall packer, the anchor packer and various forms of screw packers. Wall packers are often equipped with a series of slips operating on a tapered cone, which are intended to support the weight of the casing or tubing on which the packer is placed. Screw connections are provided at top and bottom for tubing or casing.

The disk wall packer (see Fig. 152) is lowered to the desired position, coupled into the column of casing at the proper point. The slips are held on the lower portion of the conical sleeve by a hinged steel disk, across the inner opening of the hollow sleeve composing the body of the packer. A weight—such as a piece of 1-in. pipe, 6 or 8 in. long—dropped from the surface when the packer is in position, breaks or dislodges the disk and releases a spring surrounding the lower sleeve and compressed between the slips and the bottom collar. This spring forces the slips upward on the tapered cone. Further lowering of the column of pipe causes the friction springs to advance the slips farther up the conical sleeve, pressing them outward until they bear against the walls of the well or against the outer casing. The slips thus support the casing or tubing, and the weight of the pipe above the packer, compressing the rubber cylinder, causes it to expand until it fills the space about the pipe.

The hook wall packer operates in a similar manner, except that the slips are held on the lower part of the conical sleeve by a hook latch, which is released by turning the casing or tubing through 180 deg. (see Fig. 152). This packer is lowered into the well on the tubing or casing, with the hook latched. When about a foot above the point where the packer is to take hold, the pipe is given a half turn to the right, thus disengaging the hook and releasing the slips. Friction springs prevent the slips and hook from turning with the pipe. After the hook is disengaged, the pipe is lowered until the slips slide up the tapered sleeve and engage the walls. This form of packer can be released by raising the casing and turning to the left until the hook is reengaged, after which it can be set at a lower position if desired. The packer can be readily withdrawn from the well without reengaging the hook.

Anchor Packers.—Disk and wall packers are used on casing or tubing which does not rest on the bottom of the well. If the pipe rests on the bottom of the hole, an anchor packer may be used at any desired point in the column of pipe. This type of packer is similar to the bottom-hole packer described above, except that the latter is equipped with a shoe on the lower end while the anchor packer has a pipe connection. It is frequently used to close the space between the two strings of pipe, or between the casing and the walls of the well, placing the proper length of casing below the packer to bring it to the desired depth in the well when the string of pipe rests on bottom. Another form, known as the "disk anchor packer," cannot be released until a hinged disk is broken by a blow with the bailer or drilling tools, or by dropping a weight upon it from the surface.

In another form of anchor packer, the two sleeves are fastened together with a coarse square thread (see Fig. 152). The metal above the thread is turned down, so that by screwing the upper sleeve down until the threads no longer engage, the two sleeves telescope freely under the influence of the superimposed weight of the pipe, bringing pressure to bear upon the ends of the rubber cylinder. This form of packer may be conveniently used on the same string of casing with a bottom packer, as, for

example, when a wall packer is to be set above a water sand, and a bottom packer on a shoulder of rock below. The bottom packer is set in the manner described above; then, by taking a light strain on the casing and turning the pipe two full turns to the right at the surface, the top packer is released from the threads and seated against its rubber cylinder. Release of tension on the pipe then expands the rubber against the walls.

Screw Packers.—The packers thus far described accomplish the expansion of the packing material merely by the superimposed weight of the casing. Another

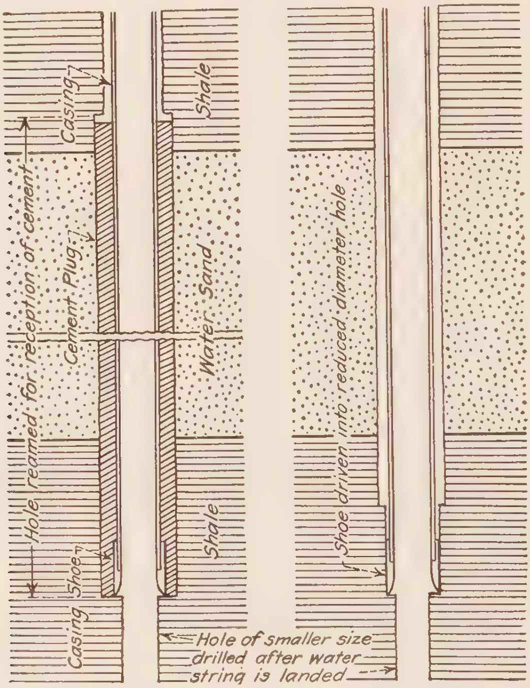


Fig. 153.—Ideal form of cement water shut-off. Fig. 154.—Formation shut-off.

type of packer is designed to operate without the aid of the weight of the casing and without the necessity of an anchor extending down to the bottom of the hole. This is the screw-down liner packer, which expands the packing material by screwing the upper of two conical metal sleeves into the lower. This packer is lowered into the well and set by means of a special "letting-in tool" mounted on a column of tubing (see Fig. 152). With this type of packer it is possible to lower a short column of casing with a packer at each end and to set both packers firmly against the walls in such a way as to exclude the water or a caving formation, though the casing does not extend either to the bottom of the hole or to the surface. Such a packer is useful for excluding water or caving material at shallow depths where the weight of the superimposed casing or tubing may be insufficient properly to expand a wall packer of the ordinary type.

Since a packer forms a permanent part of the well equipment, it must be constructed of material that will be long lived and must not obstruct the free passage of tools or other well equipment through it. In some instances, packers must be gas-tight, a feature which is accomplished by a special rubber seal between the tele-

scoping metal parts. Packers equipped with rubber cylinders are best adapted for use in hard rocks that do not crumble under the side pressures developed. For use in loosely cemented, unconsolidated formations, such packers are little used, the canvas packer being generally preferred.

Formation Shut-offs.—For many years prior to the development of cementing methods it was customary in the fields of the western United States to exclude water from oil wells by what is called the "formation shut-off." In excluding water by this method it is first necessary to reach a bed of some substantial, impervious material, such as hard shale or "shell," in which to accomplish the shut-off. When the casing has been properly landed on such a stratum, a hole slightly smaller than the casing is drilled for a few feet below the shoe and the casing is driven into the pocket thus prepared (see Fig. 154). The frictional pressure about the lower end of the casing thus developed, usually aided by accumulation of clay and detritus from the sludge in the well, is often sufficient to seal off overlying waters effectively. This method of water exclusion, however, is not always successful, and even though it may apparently be so at the time it is made, in a later period, when water has had time to accumulate back of the casing, it may and often does become ineffective.

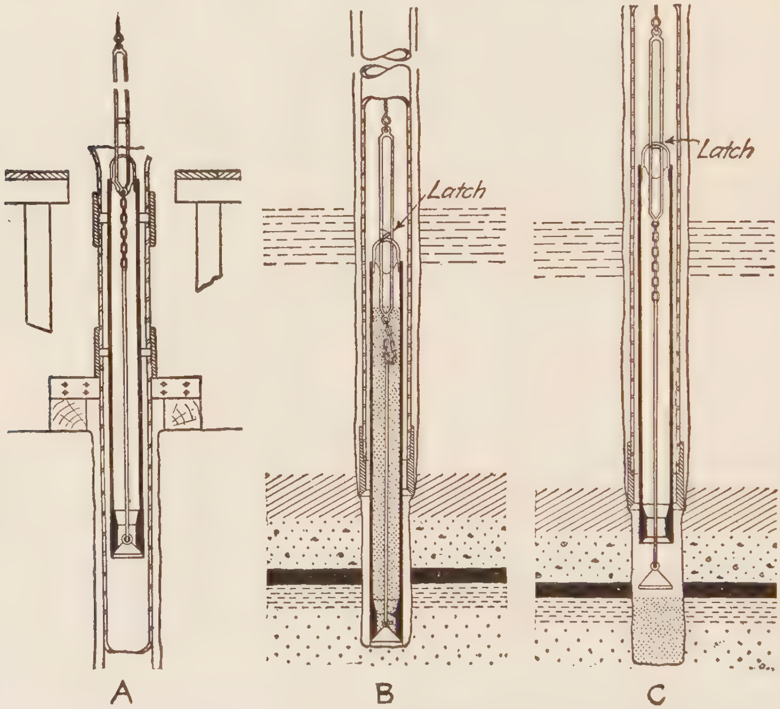
CEMENTING CASING

The most effective methods yet devised for the exclusion of top waters make use of cement, which is forced in a fluid condition into the annular space between the walls of the well and the casing, and allowed to set and harden, forming a permanent and impervious barrier to the downward movement of top water (see Fig. 153). Portland cement mixed "neat" (without sand) in from 35 to 50 per cent of water is commonly employed.

Several different methods have been developed for accomplishing the insertion of the cement into the well. In an early method the liquid cement was lowered in specially constructed bailers which dump on reaching bottom. Later methods made use of auxiliary tubing through which the cement was pumped to the bottom of the well. In more modern methods, widely employed at the present time, the cement is pumped directly into the well casing.

The procedure to be followed in cementing a water string will depend to some extent upon the method of drilling used. If cable tools are employed, a low fluid level may be carried in the well, the fluid consisting chiefly of water so that the walls are not thoroughly mudded. In such a case it may be difficult or impossible to fill the well with fluid and secure circulation down through the casing and back to the surface. On the other hand, when the rotary method is being used, the hole is necessarily left full of fluid and the walls are thoroughly mudded so that they are

impervious to the passage of fluids either into or from the well. The well fluid in this case is a mud-laden fluid and it may be unsafe to displace it with clear water. Smaller quantities of cement are generally used where the cable tools are employed so that the bailer method or tubing methods are often applied. When the rotary method of drilling is used and circulation back to the surface is easy of attainment, the methods of pumping cement directly through the casing—preferably with barrier plugs—are commonly used.



(*After Swigart and Beecher, U. S. Bur. Mines, Bull.* 232.)

FIG. 155.—Illustrating operation of latch-jack dump bailer.

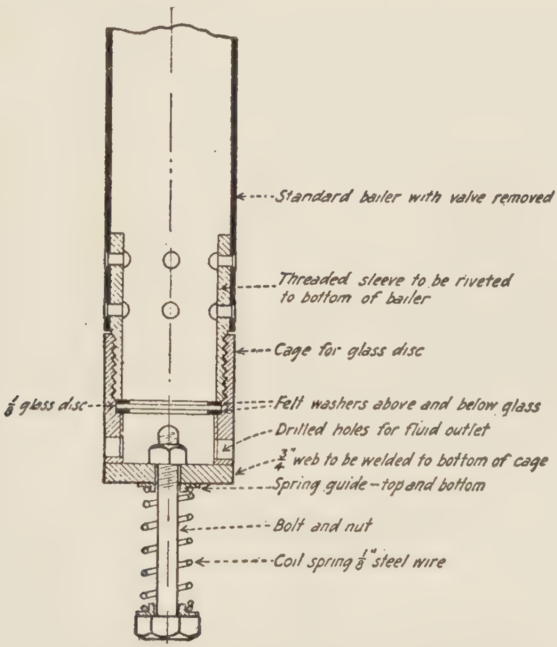
A, bailer entering well, lower end closed; *B*, bailer at bottom of well, ready to dump; *C*, after dumping, valve held open by latch.

Bailer Method of Cementing.—For lowering cement into a well special forms of bailers are employed, the one illustrated in Fig. 155 being typical. Another form, closed at the lower end with a glass disk, is illustrated in Fig. 156. The glass is broken by the bolt plunger on reaching bottom.[22]

Dump shoes, designed to be attached to the lower end of a bailer in place of the ordinary bailer shoe and valve, or to the lower end of a joint or two of tubing or casing, are more positive in action than latch-jack or glass-bottomed bailers and permit of lowering a batch of cement slurry to the bottom of the well with little likelihood of dumping before that point is

reached. A common form of dump shoe is provided with a cylindrical sleeve fitted to slide over the coupling which connects the device to the lower end of the bailer. Curved slots cut in the sleeve, operating on screw heads as guides, cause the bottom valve to open on striking bottom.

The cement is mixed in a wooden or metal box placed at a slight elevation above the derrick floor and flows through an inclined trough leading directly to the well. A lip on this trough serves to guide the cement into the bailer, which is suspended in the well with the top



(*After H. B. Thompson, California State Mining Bureau, Department of Oil and Gas.*)
FIG. 156.—Glass-bottom dump bailer.

immediately below the discharge end of the trough. The bailer must make several trips to the bottom of the well, inasmuch as several tons of cement will ordinarily be necessary. When all the cement has been deposited on bottom, the casing is raised until the shoe is above the cement level and the well and casing are filled with water. The upper end of the casing is then plugged and the column lowered to bottom. The water within the casing, being unable to escape, prevents the cement from entering the lower end of the pipe as it is lowered, thus forcing the cement to assume its desired position about the lower end of the casing. After the pipe has been lowered to bottom, it should be driven ahead for a few feet, to prevent the cement from finding its way under the shoe before the initial set occurs.

Instead of filling the casing and well with water, which may be tedious or difficult of accomplishment if the formation tends to absorb water, a cementing plug may be used. Cementing plugs for this purpose may be had in several forms, designed in each case to close the lower end of the casing so that cement may not enter when it is lowered to bottom through cement slurry. The Baker Sure Shot plug, construction of which is illustrated in Fig. 157, is a well-known type. This plug is made of cast iron and is equipped with a rubber facing ring and a canvas hood, the function of which is to wedge the plug in the casing. After the cement has been placed, with the casing suspended so that it is free of the cement, the plug is lowered through the casing attached to the cable drilling tools or to the dart of the bailer, with the canvas hood folded back so that it follows the plug during its descent. A valve in the lower part of the plug, normally closed, is forced open by the weight of the bailer or tools on the valve stem while the device is being lowered through the casing, thus permitting the well fluid to pass upward through the plug. After the plug has passed through the casing shoe, it is raised, and the canvas hood, which is by this reversal of motion drawn down over the plug, securely wedges the latter in the casing shoe. After the casing has been set on bottom, a quick jerk breaks the few strands of wire by which the plug is suspended from the bailer or tools so that the latter can be withdrawn. The plug, together with the small quantity of cement which may be left inside the casing shoe, can be readily drilled up with the tools after the cement has set and hardened. Cementing plugs are necessarily made to pass through the casing with small clearance, and it is a good precaution before attempting to use one to lower a casing swedge of appropriate size through the casing, to be certain that it has not become dented, bent or otherwise distorted during insertion.

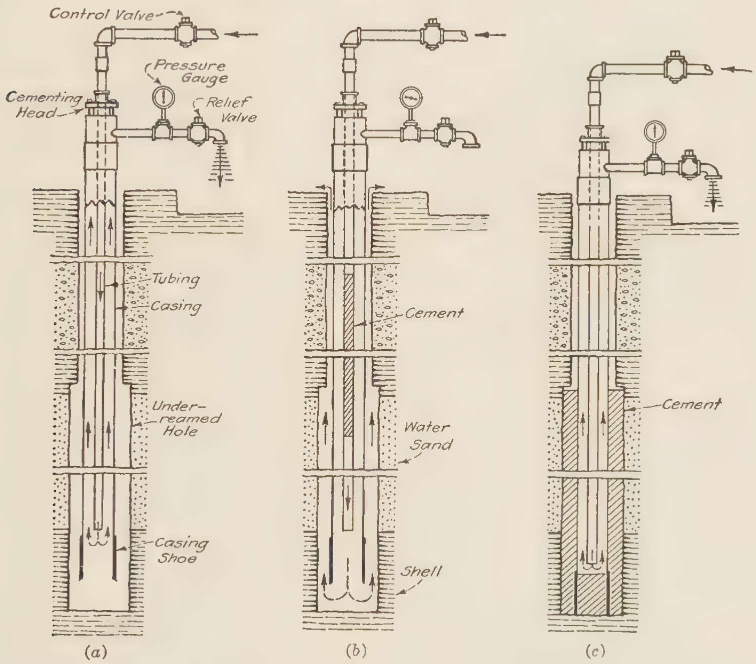
(*Baker Oil Tools, Inc.*)

FIG. 157.—Baker Sure Shot cement plug.

Tubing Methods.—Placing cement in the well by one or another of the tubing methods requires the use of a pump and a column of 2- or 3-in. tubing extending down from the surface, inside of the casing, to within a few feet of the bottom. In order to prevent the cement, which is pumped down through the tubing, from accumulating within instead of outside of the casing, a packing device or "retainer," filling the annular space between the tubing and casing, is provided either at the lower end of the casing ("bottom-packer method") or at the casing head ("top-packer

method") (see Fig. 158). In either case, but especially in the latter, the casing should be filled with water.

For use as a packer on the lower end of the tubing a disk or bushing screwed to the tubing by a left-hand thread may be used. The outer diameter of the disk is such that it fits snugly inside of the casing, but there must be sufficient clearance to assure its free passage as the tubing is lowered. Other more elaborate types of retainers may be used on the lower end of the tubing, such as the Graham packer, illustrated in Fig.



(*After F. B. Tough, U. S. Bur. Mines, Bull.* 163.)

FIG. 158.—Three stages in the tubing method of introducing cement.

(*a*) circulation established through tubing and casing; (*b*) cement passing down through tubing, circulation under shoe of casing; (*c*) cement in place, circulation again through casing, casing lowered to bottom.

159, or a cement retainer such as that illustrated in Fig. 160. If the packer is to be placed at the top of the column of casing instead of at the bottom, any form of stuffing-box casing head may be used (see Fig. 161), and if cement is to be prevented from entering the lower end of the casing, the well must be filled with water.[22]

Since the cement must be forced under the shoe and up behind the casing, it is necessary that circulation down through the casing or tubing and up to the surface be established before the cement is inserted. Assuming that it has been possible to secure circulation by applying pump pressure, the tubing and packer are placed in position with the casing

shoe a few feet off bottom; pump connections are provided and arrangements made for mixing the cement.

After the cement has been pumped into the tubing, the pump suction is switched to a supply of water, which serves to cleanse the pump and tubing of cement and force the latter to the bottom of the well. On emerging from the lower end of the tubing near the casing shoe, the cement is unable to enter the space within the casing and is forced out

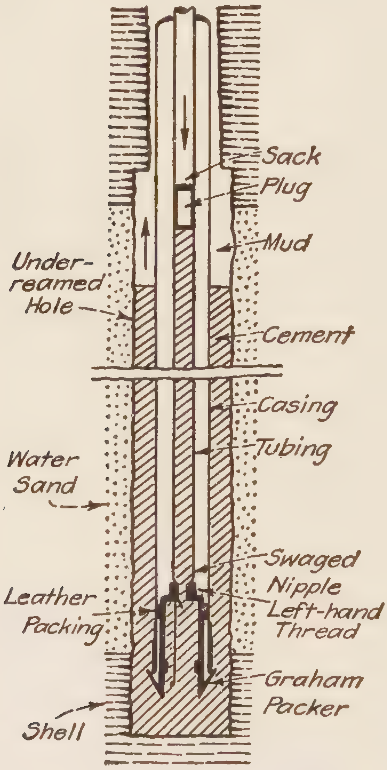
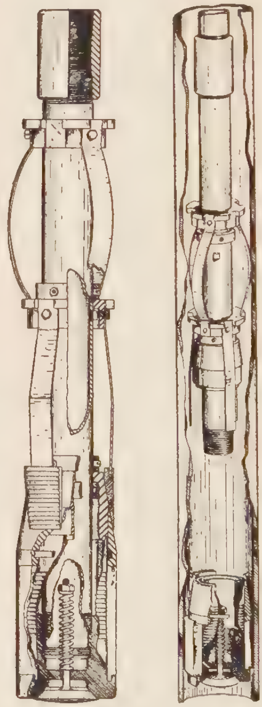


FIG. 159.—Tubing method of cementing wells using bottom packer.



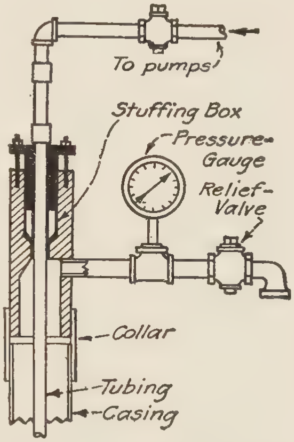
(*Baker Oil Tools, Inc.*)
FIG. 160.—Baker cement retainer.
Left: as lowered on tubing; right: set in lower end of casing.

under the shoe, accumulating in the annular space between the casing and the walls of the well.

It is important to stop pumping when the cement is all out of the tubing, otherwise it will be forced too high above the shoe and will become much diluted with water. The time to stop pumping may be determined by calculating the volumetric capacity of the tubing and by keeping account of the volume of water pumped down on top of the cement. This may be done by pumping the water from a gaging tank or through a water

meter, or it may be done approximately by counting the strokes of the pump if the capacity per stroke is known. In a somewhat more positive method, a restriction (such as a swaged nipple) is placed on the bottom of the tubing, and a small wooden plug is pumped down through the tubing ahead of the water which follows the cement. When the plug reaches the restriction in the end of the tubing, it is unable to pass, the pump pressure suddenly increases and the operator knows that all cement is out of the tubing (see Fig. 159).

After the cement has reached its proper position outside of the casing, the latter is given a few turns to distribute the cement about it and then lowered until the shoe rests on bottom. A little cement will generally find its way into the casing as this is done, and if the top-packer method has been used, the surplus cement can be flushed back to the surface through the casing by pumping more water down through the tubing. In any case, the tubing and packer must be raised above possible contact with any cement which may have found its way inside of the casing before the cement has taken its initial set. On withdrawing the tubing, the casing should be left filled with water in order to prevent cement from finding its way back into the casing through any channel which might be left under the shoe in case the latter does not rest squarely on bottom. Hydrostatic head should be maintained within the casing until the cement has properly set. Some operators consider it good practice to hold a pump pressure of 50 lb. at the casing head during the setting period as an added precaution. Cement left within the casing must be drilled out when drilling is resumed, an operation which may split or otherwise damage the casing; or it may so jar the pipe and the surrounding cement plug that the latter is loosened from the pipe or the walls of the well or is so badly fractured that it is no longer water-tight.



(*After F. B. Tough, U. S. Bur. Mines, Bull.* 163.)

Fig. 161.—Arrangements at casing head for cementing under pressure by tubing method.

Methods of Placing Cement by Pumping Directly through Casing

Development of the tubing methods described above led eventually to the pumping of cement directly into the casing. This may be done according to either of two methods. One of these, a patented method known as the "Perkins process," involves pumping the cement down through the casing between moving plugs or barriers in such a way that it does not become mixed with the well fluid until it is discharged from

the lower end of the casing. In the second method, the casing is filled with water or mud fluid and the cement pumped down through the casing, displacing the well fluid, without barriers of any sort.

The Perkins process for cementing casing, as ordinarily applied, utilizes a pair of wooden plugs, accurately turned and equipped with rubber, leather or metal washers of such size as to pass, with slight friction, through the well casing. One of these plugs moves down through the casing under the influence of pump pressure, in advance of the cement slurry, and one behind. Water or mud fluid must be pumped down through the casing after the second plug in order to provide a non-compressible pressure-transmission medium, necessary in moving the plugs and cement column against the well friction. The two plugs not only serve to prevent contamination and dilution of the cement by the well fluid during passage through the casing but also provide a means of indicating to the operator when the cement has passed out of the casing.

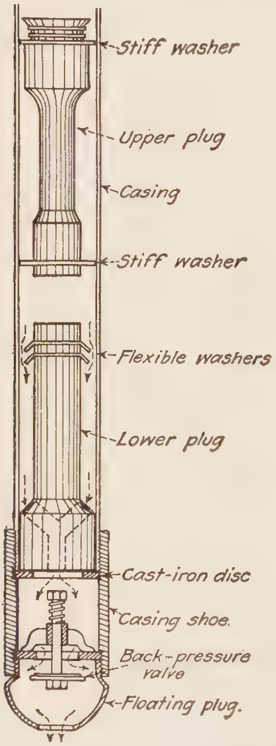
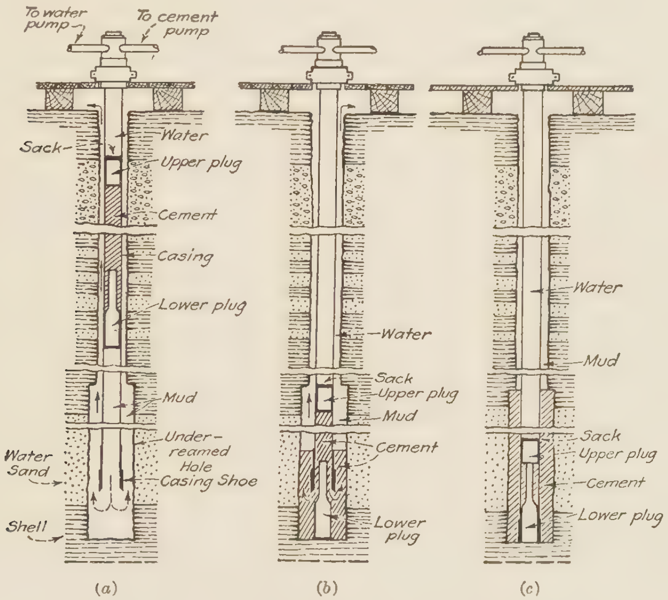


FIG. 162.—Perkins cementing plugs used in connection with floating plug and back-pressure valve.

The plugs used are of various forms, but those illustrated in Fig. 162 are typical. The lower plug is turned to a bottle-neck form below its flexible rubber washer. When this plug comes to rest on the floating plug at the casing shoe, or on a perforated-disk baffle plate placed in the casing a joint or two above the shoe, the washer, being flexible, yields to the pump pressure and permits the cement to pass. As shown in Fig. 162, the cement passes through holes bored in the lower portion of the plug, thence through the floating plug on the lower end of the casing and out into the well. In earlier applications of the Perkins process, the casing was supported with its lower end only a few inches off bottom, and the lower plug was permitted to pass out of the casing, coming to rest on the bottom of the well, so that only the upper bottle-neck end projected up inside of the casing shoe (see Fig. 163).

Continued pumping will eventually force all but a little of the cement out of the casing, and the upper plug, which follows the cement, will come to rest on the lower plug. The washers on the upper plug are stiff and do not yield to the pump pressure, hence, as soon as it is stopped by the lower plug, circulation is cut off. The pump pressure builds up rapidly and the operator knows that the cement has passed out of the casing.

The latter is then lowered until the shoe rests on bottom and may be driven into the bottom for a few feet to close all possible channels through which the cement might find its way back into the casing. A back-pressure valve in the floating plug gives added security. Pump pressure should be held on the casing head until the cement has set. After the cement has had time to harden, the two Perkins plugs, the back-pressure valve, the floating plug and such residual cement as may remain in the lower end of the casing can be drilled out without great difficulty with either cable or rotary tools.



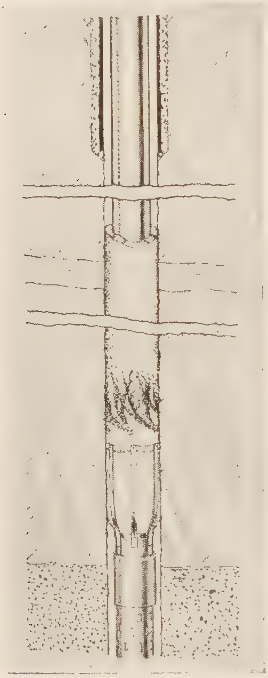
(*After F. B. Tough, U. S. Bur. Mines, Bull.* 163.)

FIG. 163.—Three stages in the Perkins process.

(*a*) plugs and cement in process of being pumped through casing: water is pumped down on top of the upper plug, the well being filled with fluid; (*b*) the lower plug and some of the cement has reached the bottom of the well, upper plug still descending; (*c*) upper plug rests on lower plug, cement is in place and casing has been lowered to bottom.

Pumping Cement Directly into Casing without Barriers.—A process used to some extent in the California fields is one which is similar to the Perkins process, described above, but operated without plugs or barriers of any sort to separate the cement from the well fluid. Two factors involved in this method tend to make the results somewhat uncertain: (1) the extent to which the cement may become diluted by admixture with the well fluid and water used in pumping, and (2) the uncertainty concerning the precise time at which the last of the cement passes out of the casing. Extensive use of the method has shown that admixture with the well fluid is not ordinarily detrimental in casings under 10 in. in diameter. The time of passage of the cement through the casing can

be calculated with fair accuracy by measuring the water used in pumping it down, using an amount equivalent in volume to that of the casing. The water so used may be gaged from a tank or through a meter. Most operators prefer to stop the pump while a little cement is still left in the pipe in order to avoid possible dilution of the cement above the shoe, though the necessity for this is doubtful since the greater density of the cement would probably cause it to sink to the bottom after flow of fluid from the casing ceases.



(*Baker Oil Tools, Inc.*)
FIG. 164.—Baker whirler cementing collar and basket.

Special Types of Cementing Operations.—In addition to the common type of cementing job, where the problem is merely one of sealing off top water by cementing a "water string," many special problems are presented in which more complex conditions must be contended with. Space permits of only brief explanation of some of these.

At times, casing is cemented through perforations provided in the pipe some distance above the bottom. This is done where a "combination string," serving both to exclude water and support the walls of the well through the oil sand, is cemented. The perforations through which the cement is forced out of the pipe are larger than those opposite the oil sand, and a heavy mud is allowed to settle in the lower part of the well, forming a "bridge," thus preventing downward passage of the cement. A cementing "basket" (see Fig. 164) may be placed on the outside of the casing below the cementing point to provide additional assurance that the cement will not move down outside the casing. The slurry is preferably introduced through tubing, the lower end of which is held opposite the cementing point. A bottom packer between the casing and the tubing prevents the cement from rising inside the casing and it is thus forced out into the well through the perforations.[8]

Occasionally a liner must be cemented inside of a water string. A liner does not extend to the surface but is cut off, in this case perhaps 100 or 200 ft. above the shoe of the telescoping water string. The liner may extend through several hundred feet of formation below the shoe of the water string, which perhaps has been landed too high structurally so that water has been encountered in the underlying formation. Water must be prevented from entering the well not only under the shoe of the liner but also by rising and overflowing the upper end. The liner, made up in appropriate length, is lowered to bottom, on a column of either

tubing or drill pipe to which it is attached by a left-hand coupling. The latter facilitates detaching after the liner has reached its position in the well and the cement has been placed. Cement is pumped down through the tubing or drill pipe and liner, under the shoe and up through the outside annular space, until the hole is filled with cement to a point well above the top of the liner. The liner is then set on bottom, the tubing or drill pipe is detached and the latter is raised above the cement. Mud or water is then circulated down through the tubing or drill pipe to remove all surplus cement. The well is then shut in, after which pressure may be applied, perhaps, forcing some of the cement about the liner into the formation. Later, the cement within the liner is drilled out. A solid liner may be cemented inside a water string in much the same manner as just described as a means of reinforcing the water string. This is sometimes done when there is danger of the casing collapsing under the influence of a greater hydrostatic head than that to which it should properly be subjected.

Plugging Wells with Cement

If a well has been drilled through a productive sand and has encountered bottom water, or if a portion of the productive zone is partially flooded with edge water, it will be necessary to seal off the water by placing a cement plug in the bottom. Occasionally bottom water will find access to the well through cavities and crevices resulting from the use of explosives to stimulate oil production. A somewhat similar operation must be accomplished in abandoning the lower portion of a well in order to produce from an upper horizon, or to redrill when the walls of the well have caved or departed from the vertical. The plugging of a well for either of these purposes may be readily accomplished by either the dump-bailer or tubing methods. The bailer method is used by preference when only a small quantity of cement is to be placed, otherwise the tubing method is resorted to.

When the tubing method is employed, the well is tubed to a point near bottom and cement slurry is pumped or siphoned into the tubing. Mud fluid or water is then run in on top of the cement until the tubing fills to the surface, indicating that equilibrium in pressure conditions has been reached. The tubing is then raised to a point just above that selected for the upper end of the cement plug and circulation continued under pump pressure down through the tubing and back to the surface through the annular space between the tubing and the casing, or *vice versa*, until all of the excess cement is washed out. The tubing is then withdrawn. If necessary to hold pressure on the well, the tubing may be packed off at the surface by a packing head on the casing and pressure applied to either the tubing or the casing.

If bottom water is to be plugged off and an oil string or liner is in the well, a somewhat more difficult condition is presented. Cement slurry must be placed both inside and outside of the lower end of the liner. In order to give the cement free access to the walls of the well outside of the liner, the latter is ripped or lightly shot with explosives. The lower portion of the hole may then be filled with sand and cement placed on top with the aid of a dump bailer or by pumping through tubing.

It is possible to control the placing of a cement plug about perforated pipe so accurately as to exclude edge water that has developed in the lower portion of a reservoir sand, or in some horizon intermediate between top and bottom, still leaving the remainder of the screen pipe open for oil production. The horizon at which water enters the well must first be accurately determined by either of the methods described in a later section of this chapter. The hole is first cleaned out to bottom and the screens or perforations thoroughly washed. If water enters at a point intermediate between top and bottom, the well is filled with sand almost up to the lower part of the water-bearing stratum. Cement is then placed with a dump bailer to fill the perforated liner or screen pipe to a point somewhat above the water-bearing member. Some of the cement slurry finds its way through the perforations or screens and develops contact with the walls of the well. After the cement has set, that within the liner is drilled out, leaving the perforations or screens with which the cement has been in contact thoroughly clogged. Sand in the lower portion of the hole may then be cleaned out and oil production secured from both above and below the cemented portion of the liner. If certain strata within an oil zone are producing mostly gas, they may be cemented off by the same method, if it is desired to conserve gas pressure, and production thus confined to the more thoroughly saturated oil sands. Operations such as these require accurate stratigraphic information and careful depth measurements, or irreparable damage may be done to the producing sands and important oil-bearing horizons sealed off.

Another method that has proved effective in cementing off bottom water is that developed by W. W. McDonald for use in the Illinois fields.* In this process a hydrostatic head is maintained in the well sufficient to cause movement of water into the sand to be cemented. Tubing is then lowered to a point from 2 to 4 ft. above the top of the sand to be cemented. Dry cement in small amounts is fed into the upper end of the tubing and washed down with water. This cement is carried into the water sand by the movement of water from the well and gradually seals the pores, simultaneously building up a cement plug within the well to the height of the lower end of the tubing. It is important to have a means of measuring the fluid level within the well as the work is in progress.

* Neal, R. O., Petroleum Hydrology Applied to the Mid-continent Field, *Trans., Am. Inst. Mining Met. Eng.*, vol. 61, pp. 565–579, 1919.

If a bottom water sand is under high pressure, the upward force of water may make it impossible to hold the liquid cement in the bottom of the well until it sets and hardens; or, perhaps, water flowing up through the cement will so agitate and dilute it that it does not set properly; or channels may be developed through or about the cement plug which render it ineffective. In such cases it is necessary to bridge or plug the bottom with some solid material, to provide a support for the cement and to protect it from the ascending waters until it can attain its initial set. Bundles of strands from annealed wire cables, cut into short lengths, with hemp or manila fiber unraveled from old rope, can be rammed into a compact mass in the bottom of a well with the drilling tools, partially to control flowing water and to serve as a foundation for a cement plug.

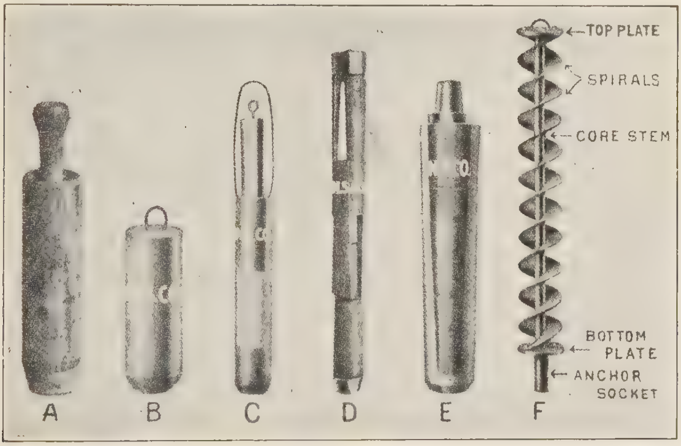


FIG. 165.—Types of plugs.

A, common wooden plug; *B*, lead plug; *C*, lead and rubber plug with mandrel; *D*, limit plug; *E*, wood and rubber plug; *F*, Guiberson-Crowell bottom water plug.

Short hook-shaped pieces of annealed wire cable strands also serve as an admirable reinforcing material for a cement plug when added strength is necessary. Lead wool placed in the well in small bundles has also been used effectively in plugging off bottom water and in preparing a foundation for a cement plug. Various forms of wooden, lead or cast-iron plugs are also available for this purpose (see Fig. 165). It may be necessary to provide a plug which will resist an upward pressure of many hundreds of pounds per square inch in cases where a strong flow of high-pressure water is encountered. In such instances it is a good plan to drill entirely through the bottom water sand, starting the plug in a lower stratum where it may obtain a formation lock that will better resist the heavy upward pressure. Mudding under high pressure, as described on page 392, is also effective in temporarily controlling the flow until a cement plug can be placed.

The Guiberson-Crowell plug is a useful device for plugging off bottom water. It consists of a pair of heavy spiral springs wrapped about a metal stem and maintained under tension, as indicated in Fig. 165, by a wooden dowel pin driven through the stem. Oakum saturated with melted pitch, tar or neat cement is packed in the space between the spirals of the spring, this material being held in position by small wires passed through holes bored in the periphery of the spirals. An anchor pipe of sufficient length to hold the packer in the desired position above bottom is screwed to the lower end of the supporting stem and the device is lowered while suspended from the drilling tools. When in place, a few blows with the tools break the wooden dowel, the stem falls through the spring into the anchor pipe, allowing the spirals to collapse and expand, pressing against the walls of the well and compressing the oakum between them. A little neat cement placed in the bottom of the hole with the bailer before placing the plug, so that the latter will be immersed in the liquid cement, further insures the success of the work.

Properties of Cements Used in Sealing Off Water in Oil Wells

In cementing oil wells, Portland cement of a special grade is often used. In selecting a cement for this purpose, desirable properties include (1) slow initial set, (2) early hardening and high early strength, (3) high density, (4) high fluidity when freshly mixed with water and (5) low permeability after setting and hardening.

As is well known, Portland cement is manufactured by a process involving the sintering of a mixture of clay and limestone in certain proportions. The cement clinker produced by the sintering furnace is essentially a solid solution of various calcium aluminates in tricalcium silicate. This clinker has no hydraulic properties until it is finely ground. During the grinding process, calcium sulphate (gypsum) is added to control the setting time and aid the cement in developing strength.

Setting of Cement.—The chemical changes which occur after the ground cement has been mixed with water, and which produce the phenomenon known as "setting," are complex and somewhat uncertain. It is probable, however, that the setting of cement involves formation of an amorphous tricalcium aluminate with or without amorphous hydrated alumina. Some authorities call these amorphous substances "colloids" or "gels." Sulphoaluminate crystals are also formed, and the finely ground lime forms hydrated lime. All of these changes occur within a few hours after the cement is mixed with water. Subsequent hardening involves hydration of the tricalcium silicate, which is ordinarily complete within 7 days. It is thought that the initial set is influenced by small amounts of electrolytes which retard the coagulation of the colloids.

Three periods are recognized in the setting and hardening of Portland cement: the so-called "initial," "final" and "hardening" sets. The physical changes which characterize these different periods are the result of certain chemical readjustments which require time to achieve. The initial set is said to have occurred when the cement slurry has lost its plasticity to such a degree that the two pieces of a broken specimen will not unite to form a homogeneous mass when placed in close contact. To obtain a coherent mass the cement slurry must rest undisturbed for a time before the initial set occurs, with the individual grains in close contact. Agitation of the slurry throughout the period of initial set will prevent the cement from hardening properly, and, even though it may consolidate into a coherent mass, its strength will be greatly impaired.

After the initial set has occurred, the cement undergoes further chemical change as a result of which it acquires greater hardness until the "final set" has been achieved. This period is of no particular significance in oil-well cementing. It is arbitrarily defined as the time necessary to reach a certain degree of rigidity as determined by

a penetration needle of standard proportions. The Gillmore and Vicat needles, designed for tests of this character, are ordinarily used.* With most Portland cements the final set occurs in from 2 to 5 hr. after the initial set. Following the final set, a 10- to 28-day period of further chemical readjustment results in gradually increasing strength and hardness. This "hardening-set" period is important in oil-well cementing operations in that during this time the well must be left undisturbed in order that the cement may not be subjected to stress beyond its ability to resist.

Accelerators.—The time of final set is somewhat diminished and the period of hardening is reduced to as little as 3 or 4 days by adding a chemical accelerator, either to the cement, or to the water used in mixing. A variety of accelerators are available on the market under different trade names, but calcium chloride is the active component of practically all of them. An alkaline substance is sometimes added to reduce the corrosive tendency of the calcium chloride. The graphs of Fig. 171 demonstrate the advantage of calcium chloride in achieving early final set and strength.

Tests made by the U. S. Bureau of Standards, in which calcium oxychloride ($3CaO.CaCl_2.14H_2O$) was used as an accelerator, have shown that mortar mixed with 5 per cent of the reagent is after 2 days the equal in strength of untreated mortar after 8 days. Fifteen per cent gives an increase in strength of 220 per cent at the 2-day period. Tests have shown that addition of calcium chloride beyond 2 per cent of the weight of the cement has little effect on setting time and strength. The addition of excessive amounts should be avoided, for it tends to diminish rather than increase ultimate strength. In field practice from 2 to 3 lb. of $CaCl_2$ is used for each sack of cement (94 lb.). A common method of application involves addition of the reagent to the water used in gaging the cement. A sufficient amount is used to form a solution having a density of 1.02 to 1.03. A solution of this density may be prepared by dissolving 3.5 lb. of calcium chloride in each cubic foot of water used. In the so-called "quick-hardening" cements, available from various manufacturers and intended to be mixed with pure water, the accelerating agent is intimately mixed with the dry cement. Cements to which an accelerating reagent has been added acquire sufficient strength and hardness in from 3 to 4 days to permit of resuming drilling operations; hence the name "four-day reagent" is sometimes applied.

Specifications for Portland Cement to Be Used in Oil-well Service.—Specifications approved by the American Society for Testing Materials are widely used by oil producers in purchasing cement for oil-well purposes.[26] A committee of the American Petroleum Institute has also given consideration to this matter. The following specifications are assembled from the recommendations of both of these authorities:

1. The cement shall be the product obtained by finely pulverizing clinker produced by calcining to incipient fusion an intimate and properly proportioned mixture of argillaceous and calcareous materials, with no additions subsequent to calcination except water and calcined or uncalcined gypsum.

2. The chemical composition shall be such that:
   (*a*) The (% CaO) ÷ (% SiO_2 − % Fe_2O_3 − % Al_2O_3) will be not less than 2.00 or greater than 2.15.
   (*b*) The (% SiO_2) ÷ (% Al_2O_3) will be not less than 1.6 or greater than 3.2.
   (*c*) The SO_3 content of the cement shall not exceed 2.00 per cent.
   (*d*) The MgO content shall not be greater than 3 per cent.

3. The loss on heating a sample to redness and maintaining at this temperature for 30 min. shall not be greater than 3 per cent.

4. The specific gravity of the undried sample, as taken from the original package, shall not be less than 3.10.

* For a description of the methods employed in testing Portland cements for oil-field purposes, the reader is referred to an article by the author in *Oil-field Engineering*, pp. 31–36, September, 1927.

5. In a screen test, using a sample of not less than 500 g. of cement,
100 per cent shall pass an 80-mesh sieve,
At least 97 per cent shall pass a 100-mesh sieve,
At least 84 per cent shall pass a 200-mesh sieve.

6. Pats of neat cement, gaged to normal consistency (25 per cent of water by weight), either with or without calcium chloride accelerator (solution of 1.025 density), shall remain firm and hard and show no signs of distortion, cracking or checking, or disintegration in the steam test for soundness.

7. The cement shall not develop initial set in less than 45 min., the Vicat needle being used in the test; or 60 min. when the Gillmore needle is used. Final set shall be attained within 10 hr.

8. Cylindrical test specimens, 2 in. in diameter and 4 in. long, shall develop a compressive strength of not less than 2,000 lb. per square inch after 3 days, and 3,500 lb. per square inch after 7 days. For this test the specimen shall be gaged with water to the extent of 40 per cent by weight of the cement. Specimens shall be cured one day in moist air and kept for the balance of the time under water at a temperature of 70°F. Test specimens gaged with a water solution of calcium chloride of 1.025 density, prepared and cured in the same manner, shall develop a compressive strength of not less than 3,500 lb. per square inch after 3 days, and 5,000 lb. after 7 days.

9. The average tensile strength in pounds per square inch for neat cement gaged with 40 per cent of water shall be equal to, or greater than, 175 lb. per square inch after 1 day in moist air; 500 lb. per square inch after 1 day in air and 6 in water; and 600 lb. per square inch after 1 day in air and 27 in water.

10. The cement shall be packed in paper sacks, or canvas cloth sacks with a paper lining. The net weight of each sack of cement shall be not less than 94 lb. The cement shall be free of all unground particles of clinker and free of any detritus such as flint chips, steel slugs and the like.

Table XXXV gives the physical and chemical properties of several well-known brands of oil-well cements commonly used in the California fields.

Special Cements.—Some cement manufacturers supply cements especially prepared for oil-well service, in which the desirable properties for this purpose are highly developed. These special oil-well cements differ from ordinary Portland cement in that they are often more finely ground and in some cases burned longer. Fine grinding gives quick-setting qualities and high early strength. Most cement mixtures prepared from such cements are, after setting, denser and less permeable than ordinary cements.

The so-called "high-alumina" cements differ considerably from ordinary Portland cement in chemical composition and yet have properties that make them attractive for oil-well service. The initial set of this type of cement is slow, but it develops unusually high early strength, being as strong after 24 hr., as ordinary Portland cement after 28 days. High-alumina cements would probably find greater use in the oil industry if it were not for their high cost.

Variables Influencing the Setting of Portland Cement

The setting time of Portland cement in oil-well service is influenced by many variables, the more important of which are the chemical composition, the percentage of water used in the mix, the temperature, pressure, the age of the cement and conditions attending storage, and the size of the cement particles. The setting properties may also be influenced by contact with ground waters containing certain dissolved salts or by the presence of flowing oil or gas.

TABLE XXXV.—PHYSICAL AND CHEMICAL PROPERTIES OF OIL-WELL CEMENTS*

Constituent	Formula	Brand of portland cement			Brand or source of hydraulic lime[d]				
		Golden gate cement,[a] per cent	Santa Cruz oil well cement,[b] per cent	Mount Diablo oil well cement,[c] per cent	German, per cent	Pacific Lime & Plaster Co., San Francisco, per cent	Cartersville, Ga., per cent	Mankato, Minn., per cent	Common or quick lime,[e] per cent
Silica	SiO_2	20.89	19.38	22.36	25.87	19.51	15.04	18.10	1.00
Ferric oxide	Fe_2O_3	3.37	5.31	2.51	8.13	12.40	.72	5.02	1.30
Alumina	Al_2O_3	7.09	7.15	7.17					
Lime	CaO	63.47	63.70	62.39	55.44	39.20	51.12	40.68	97.00
Magnesia	MgO	1.32	2.13	1.39	1.14	20.61	29.53	29.17	.70
Sulphuric anhydride	SO_3	1.19	1.48	1.45	1.44	1.65	Trace.	2.05	
Ignition loss	......	1.54	1.04	2.09	1.96	.46	3.54	4.56	
Manganese oxide	MnO	.....	.....	.....	.....	.....	.....	.42	
Carbon dioxide	......	.....	.....	.....	6.02	6.17			
Specific gravity	......	3.12	3.20	3.12					

[a] Pacific Portland Cement Co., San Francisco, Calif. Analysis made by the company.

[b] Santa Cruz Portland Cement Co., San Francisco, Calif. Analysis made by the company.

[c] Cowell Portland Cement Co., San Francisco, Calif. Analysis made by the company.

[d] Analyses furnished by Dr. E. A. Starke, San Francisco, Calif.

[e] Marks, L. S., "Mechanical Engineers' Handbook," p. 568, McGraw-Hill Book Company, Inc., New York, 1916.

* After F. B. Tough, U. S. Bur. Mines, *Bull.* 163.

From the chemical point of view the setting time of Portland cement is influenced by the percentage of free lime present, the alumina and silica content and the amount of gypsum or plaster of paris used in its manufacture. Deficiency of lime makes the cement quick setting if it is "under burned," or slow setting if it is "hard burned." Excessively high lime content tends to make the cement slow setting. High alumina content results in quick-setting properties, whereas a high silica content produces a slow-setting cement. Addition of gypsum or calcium sulphate up to 2 or 3 per cent retards the set, but further additions cause the setting time to decrease. Introduction of 10 to 20 per cent of plaster of paris will greatly hasten the setting time.

The influence of saline ground waters on the setting qualities and life of Portland cement in oil-well service has been noted by many observers. Portland cements are quite sensitive to comparatively small percentages of some of these salts, and if there is any flow of saline water into the well during the placing or setting of the cement its properties may be greatly altered. In extreme cases the cement does not set and must be pumped out of the well. Addition of small percentages of calcium chloride or sodium carbonate hastens the time of setting, but sodium chloride has the reverse effect. Contact with any sulphates will generally delay the time of setting. The graphs of Fig. 166 give the results of tests made with a typical oil-well cement gaged with 50 per cent of water containing varying percentages of dissolved salts commonly present in oil-field ground waters. Tests made with a number of actual ground waters from the San Joaquin Valley fields of California showed in every case considerable delay in the setting time. If brackish surface waters are used in mixing cements, they may seriously alter the setting time.

Some of these salts, particularly salts of the alkalies and alkaline earths, in addition to influencing the setting time, will on prolonged contact with cement cause it to

disintegrate. Sulphates of magnesium and sodium, chlorides of magnesium and sodium, and carbonate of soda are particularly active in causing "unsoundness" in neat Portland cement. Cements containing high percentages of ferric oxide in substitution for alumina are said to be more resistant to saline waters than ordinary cements. The sulphates and chlorides remove lime from the cement, while carbonate of soda withdraws silica. Unsoundness of cement may also be due to expansion as

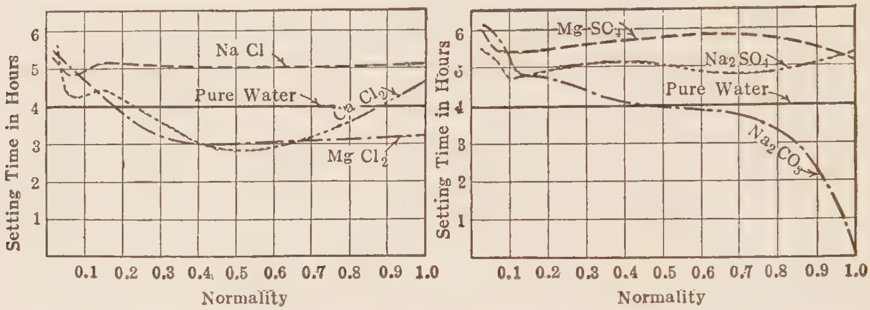
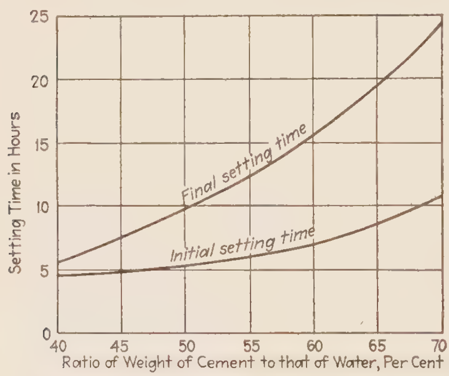


FIG. 166.—Graphs showing influence of dissolved salts on setting time of oil well cement.

a result of belated crystallization of free lime and magnesia present in the cement itself. More than 5 per cent of magnesia is considered detrimental in a Portland cement for this reason. Failure of the cement through such causes will not be apparent at first but may eventually result in crumbling and disintegration and its ultimate failure in water exclusion. The amount of "laitance" which forms on top of cement during the setting period is considered to be indicative of the degree of unsoundness of the cement.



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 167.—Graphs showing effect of dilution of cement slurry on setting time. (Slurry mixed with solution of McDuffie's reagent, sp. gr. 1.005.)

Dilution of the cement mixture with water prolongs the setting time. If the mixture is diluted to such a degree that the cement particles are held apart by suspension, they cannot be expected to form a coherent mass even though setting of the individual particles does occur. Though a smaller percentage of water would be preferable, a mixture containing 40 per cent of water (by weight) is about as thick as can be rapidly handled through pumps, piping and other apparatus used in oil-well cementing. Tests made in the petroleum laboratory of the University of California have shown in the case of a typical oil-well cement that the setting time increases directly with the percentage of water until the percentage of water reaches about 70 per cent, and that the setting time is only slightly influenced by further dilution (see Fig. 167). The presence of too much water may prevent the formation of a coherent, solid mass, through the individual grains taking their initial set when not in contact. However, if there is adequate time for the cement particles to settle before the time comes for the initial set, a successful job is possible.

Though cement may be pumped into the well with only 40 or 50 per cent of water, it will frequently be further diluted by admixture with the well fluid and with the

water used in pumping the cement down through the casing or tubing. It is well known that in pumping fluids through a pipe the fluid near the center moves more rapidly than that near the walls of the tube as a result of frictional resistance. Furthermore, turbulence is usually induced. Hence, when cement is pumped into a pipe containing water or mud, there is more or less dilution of the first portion of the cement introduced. A similar effect results when water is pumped in after the cement. The amount of dilution and admixture would vary with the diameter of the pipe and the velocity of flow, being greater in pipes of large diameter and at high-flow velocities. Even when barriers are used between the cement and the well fluid, as in the Perkins method, the two fluids must come into contact when the cement emerges below the casing shoe. Reversal in the direction of flow as the cement strikes the bottom of the well and is deflected upward, and contamination with mud from the walls as it rises, inevitably results in considerable dilution of the material that forms the top of the plug. Again, in the method of cementing direct through the casing without barriers, unless pumping is discontinued at the proper time, water forced in below the cement will rise slowly and become diffused through the latter by reason of its lower density.

Dilution with mud may seriously reduce the strength of cement, though it may set satisfactorily even when contaminated with considerable amounts. The mixture will be coherent and impermeable, but it lacks strength. Briquettes made of a mixture of equal parts of a mud-laden fluid of specific gravity 1.2 with a 50 per cent cement grout had a compressive strength of only 97 lb. per square inch after setting 10 days in air, while a pure 50 per cent cement grout, under similar conditions, had a compressive strength of 2,210 lb. per square inch.

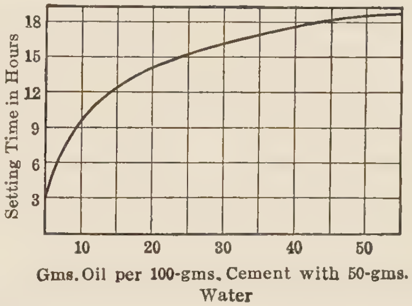


FIG. 168.—Graph showing influence of oil dilution on setting time of oil well cement.

Probably only the upper portion of a cement plug is contaminated with mud to an important degree, the heavier cement, injected below the column of mud, tending to float the latter so that the lower part of the plug should be fairly free of mud. However where conditions are such as to permit the cement to channel through a column of heavy mud, it is easy to understand how contamination of the entire body of cement might result. Engineers in the employ of the Humble Oil and Refining Company conducted a series of tests on cores taken in drilling cement plugs out of casings. The cement was found to lack strength in many cases and to have a chalky, unsound appearance. Petrographic and chemical inspection indicated that mud contamination was the principal cause and the conclusion was reached that even small amounts of drilling mud are capable of doing considerable damage.

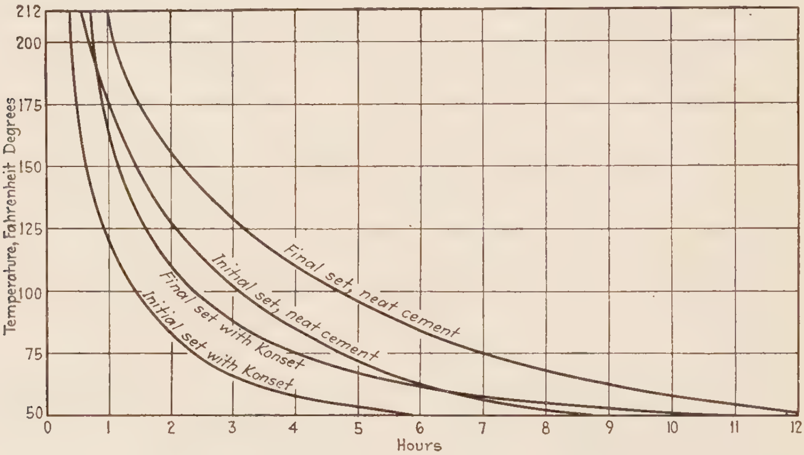
Mixture of oil with Portland cement slurry will not prevent setting, providing there is sufficient water present to hydrolyze the material properly, but it has the effect of prolonging the setting time. Figure 168 illustrates the effect of oil admixture in delaying the initial set of a typical oil-well cement. Oil may also prevent the cement from adhering to the casing, leaving a crevice through which water eventually finds its way to the lower part of the well. Perhaps this leakage is negligible at first, but is later increased by the solvent action of percolating alkaline ground waters.

The presence of gas in the bottom of a well is a more serious matter. Violent agitation of the cement sometimes prevents it from setting into a coherent mass, while even comparatively small quantities of gas continually supplied from a point below the plug will, in seeking an outlet, leave pores in the cement which will later become channels for the passage of water. If a well is producing gas in quantity, it

should be possible to hold pressure on it during the process of cementing to prevent flow of gas. Preliminary mudding under pressure will often "kill" the gas so that cementing operations may be safely conducted at lower pressures.

The setting qualities of Portland cement are also influenced by the degree of fineness to which the components are ground. Most cements are ground so that all but 2 or 3 per cent of the material will pass a 100-mesh screen, while about 85 per cent usually passes 200 mesh. The coarse material which does not pass 100 mesh is probably inert and never sets. Tests made by Meade[27] with a certain cement show a setting time of 30 min. when 95 per cent passes 200 mesh, while the same material ground so that only 75 per cent passes 100 mesh requires 170 min. in which to take its initial set. Uniformity in sizing is found to be one of the most important considerations in the manufacture of a reliable product.

The setting time of Portland cement is greatly influenced by temperature. As indicated by the graphs in Fig. 169, some cements set in one-third of the time at 150°F.



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 169.—Graphs showing effect of temperature and accelerators on the setting time of 40 per cent cement slurry.

that is required for the same cements at 60°F. In the deeper wells ground temperatures of upward of 150°F. are not unusual, and the setting time is decreased to such an extent that a difficult problem is presented in getting the cement into position outside the casing, before the initial set occurs. In one of the California fields operators have used ice water in mixing the cement in an effort to offset high ground temperatures. The use of saline water in mixing might be an alternative plan. One cement manufacturer has met this problem by coarser grinding of the cement.

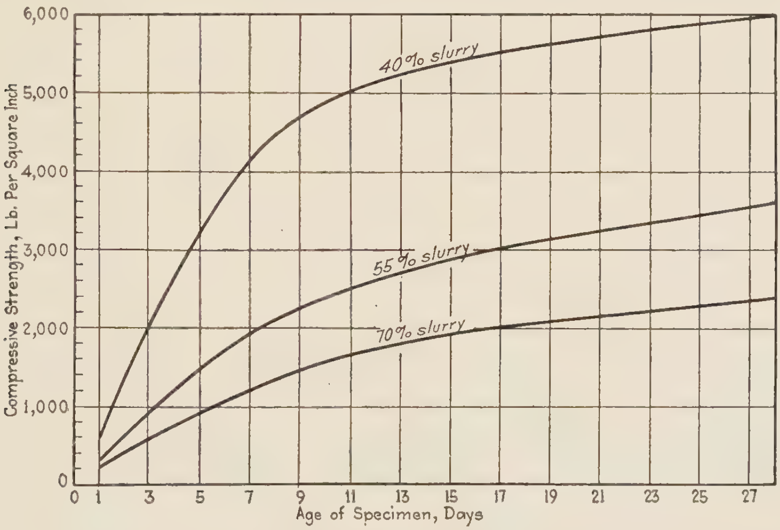
Pressure apparently has little influence on the setting time of Portland cement. In certain tests, a pressure of 1,500 lb. per square inch caused a reduction in initial setting time of only about ½ hr. in 7½ hr. High pressure, however, has been found to be responsible for an increase in compressive strength of as much as 30 per cent in some cases.

Portland cement in storage inevitably undergoes a certain change in chemical composition that greatly alters its setting time. This is due to hydrolyzing of the lime as a result of contact with moisture in the air. This change operates to prolong the necessary setting time. Certain cements stored in a dry room for a period of 6 months have increased their setting times from 2 to 4 and even 5 hr. in some cases. The rate of change is, of course, primarily influenced by the conditions attending

storage. For uniformity in results, cement should be purchased direct from the manufacturers and in quantities that will not require prolonged storage. This is particularly important when operating in moist climates. The place of storage should be absolutely dry.

Properties of Portland Cement of Importance in Oil-well Cementing

The strength of Portland cement after setting and hardening has been previously discussed in its relation to mud contamination and hydrostatic pressure. It appears also as one of the important considerations in connection with cement specifications. Stresses of considerable magnitude may conceivably be brought to bear on the cement plug formed about a column of casing and the cement must develop sufficient strength to successfully resist such stresses. After cementing a string of casing and drilling the well to greater depth, caving of the underlying formation may result in the full



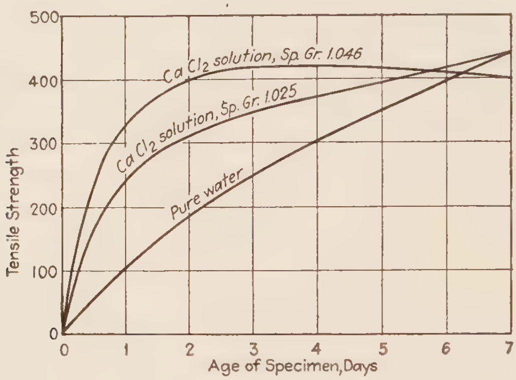
(After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.)

Fig. 170.—Graphs showing influence of age and water content on compressive strength of neat cement mixtures.

weight of the column of pipe being thrown on the cement plug. Either compression or tensional stress may be brought to bear under different circumstances. Drilling out the plugs and residual cement left in the lower end of the casing and in the bottom of the well after a cementing job may throw important compressive strains on the cement about the shoe, causing, perhaps, cracking. Movement of pipe down the hole through the cement plug may result from shearing of cement below the shoe and collars, though the frictional hold of a long cement plug should be sufficient to prevent this except in cases where the cement fails to harden properly.

The strength of cement is largely dependent upon density, and density is influenced by pressure. The lower portion of a cement plug is naturally denser than the upper portion, because of the greater amount of cement condensed within the liquid mass as a result of greater hydrostatic head and also because of the tendency of the cement particles to settle toward the bottom before setting occurs. As a result of this settling of the cement particles, the slurry forming the upper portion of the plug is more dilute

than that forming the lower part and its ultimate strength, after setting and hardening, is lower. Tests made with a 14-in. column of cement indicated a tensile strength of only 150 lb. per square inch for the upper part of the column while a section from the lower end had a tensile strength of 280 lb. per square inch. Other sections, cut at intervals between the top and bottom, indicated a fairly uniform increase in strength and density with depth below the cement surface. Figures 170 and 171 indicate the influence of age, dilution and accelerators on tensile and compressive strengths of cement.



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 171.—Graphs showing effect of age and influence of accelerators on tensile strength of cement.

High density of cement slurry is important in facilitating its rapid placement in the well. A heavy mixture sinks more rapidly through the casing and settles after reaching its position outside of the casing to form a more compact mass which develops greater strength on setting and hardening.

The fluidity or viscosity of the cement slurry is important to the operator in determining the ease with which it may be pumped. Neat cement mixtures of high water content are more readily handled by the pumps and with lower well resistance, but, as has been shown, high dilution of the slurry prolongs the setting time and reduces the strength of the resulting cement. The percentage of water used in the mixture must therefore be a compromise between these opposing factors. The fluidity of cement slurry may be increased and lower percentages of water used in the mix by the addition of small quantities of certain alkaline reagents such as sodium carbonate, sodium silicate or sulphite lye. The last has been found most effective in certain tests, in which 1 per cent of the reagent was used. The use of such reagents necessarily alters the setting time.

Cement permeability is of interest as a measure of the resistance offered to movement of fluids. After a cement plug has set and hardened, it may still permit movement of high-pressure water or gas through its pore interstices unless high density and low permeability are attained. However, tests have indicated that the permeability of neat cement mixtures is ordinarily very small, even when mixed with as much as 70 per cent of water, and it is considered probable that when movement of water or gas apparently occurs through a properly set and hardened cement plug, it is in most cases due to leakage around the plug or to openings left as a result of gas blowing through the cement during the setting period or to failure of the cement entirely to close the space around the casing.

Penetration of Wall Rocks by the Cement.—An important consideration in the formation of a cement plug to resist water infiltration is the extent to which the fluid cement penetrates the rock pores before setting. It is probable that under high pressures the cement not only fills the space within the well but is also forced into all crevices and even into the pores of sands and granular wall rocks, thus forming what may be called a formation lock on the walls of the well. The extent to which this action will occur depends upon the excess of pressure within the well and the permeability of the wall rocks.

To be effective, the cement plug must at some point below the source of the water be in contact with a relatively impervious stratum, otherwise water may find its way through the formation around the cement plug and thence into the lower portion of the well below the plug. In an extension of the Kern River field of California this difficulty was experienced but successfully met by forming long cement plugs about the casing and applying a pump pressure of 1,200 lb. per square inch (in addition to the natural hydrostatic head), which forced large amounts of cement into the wall rocks surrounding the well, thus preventing downward migration of water through the formation about the plug. The cement was introduced in this case by the top-packer tubing method.

Preparing the Well for Cementing.—If cement is to be pumped into a well, circulation must first be established from the lower end of the column of casing to the surface by pumping fluid under pressure through the space between the walls of the well and the casing. If the formation tends to absorb large quantities of fluid, this may be difficult, but until a free path for the cement, outside of the pipe, is assured, none should be introduced. Circulation should be continued until all coarse detrital material and gas-cut mud and surplus clay have been removed and the well fluid has been brought to uniform consistency. The density of the fluid should be as low as may be consistent with safety, in order to permit the cement slurry to displace it with minimum pump pressure.

Apparently, in some cases, free circulation is established, but the flow is through channels on only one side of the pipe or through spiral channels about it. Considerable mud may thus remain lodged about the lower end of the casing and, as the cement is introduced, it rises through the channels already established by circulation, and an irregular plug consisting partly of cement and partly of mud will result. Water strings pulled from wells after unsuccessful cementing jobs have shown clearly in certain instances the spiral contact of cement against the casing. This can be avoided only by continuing circulation, with occasional lifting and rotation of the casing, until all surplus detrital material is removed.

If the casing is nearly as large in diameter as the well, there is danger of the pipe making contact with the walls on one side or another so that when the cement is introduced, it does not form a plug concentric with the axis of the pipe. As a means of preventing this, it is a good plan to under-ream the hole for 25 or 50 ft. above bottom, thus assuring sufficient free space to form a plug which will be thick enough to be effective all about the lower end of the casing. Some operators follow the plan of placing guides or wooden ring bands on the outside of the bottom two or three joints as a means of keeping the pipe centered in the hole.

It is important that the diameter of the hole be proportioned to that of the casing, not only to afford sufficient space for the cement to form a continuous cement plug of proper thickness, but also to provide proper ascending velocity for the cement slurry. The ascending velocity of the fluid outside of the casing should be greater than that of the descending column within. If the diameter of the hole is too great, the cement tends to settle and coagulate and perhaps attain its initial set before it is all displaced from the casing. Case[9] suggests the formula

$$D^2 = 2d^2$$

for computing the diameter of hole to be drilled. In this formula D is the diameter of the hole and d the inside diameter of the casing. This gives the maximum diameter of the hole if the ascending velocity is to be greater than that of the descending velocity. The following values for D have been computed, with the aid of this formula, for different commonly used sizes of casing.

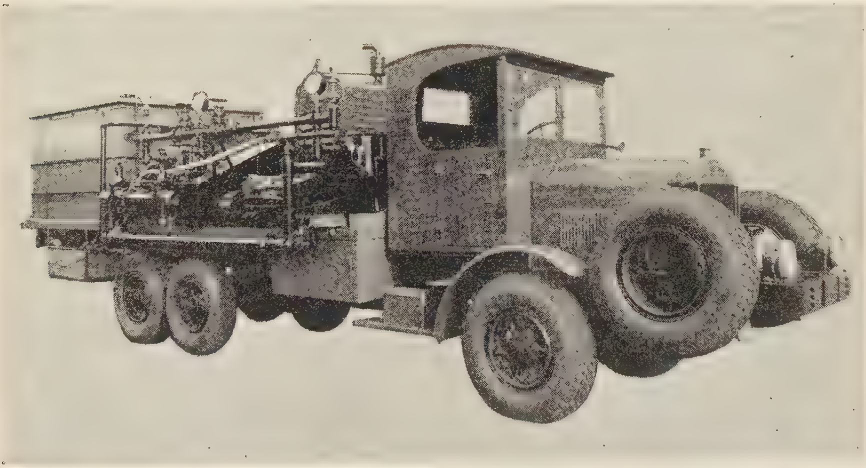
Diameter of Casing d, In.	Maximum Diameter of Well D, In.
12½	17.66
11	15.55
10	14.00
8¼	11.66
6¼	8.85

Mixing and Placing the Cement

The method provided for mixing the cement must be capable of accomplishing its purpose rapidly and thoroughly, so that the entire amount of cement to be used may be in place in the well within 1 hr. of the time that mixing begins. This is essential, for a successful result is impossible if the cement takes its initial set before it reaches its intended position. The use of dump bailers for placing cement has already been mentioned, but this method is suitable only when a small amount of cement is to be used. For the ordinary cementing jobs where casing is to be cemented and several tons of cement must be mixed and placed within an hour's time, pumping methods must be resorted to. The Perkins process, described in general terms in an earlier section, is the one generally used, though some operators successfully cement their wells without barrier plugs to separate the cement slurry from the well fluid. Several different types of equipment are used for mixing the cement, irrespective of the method of getting it into position in the well.

The Perkins Cementing Outfit.—Cementing jobs are often conducted by contracting companies equipped with especially designed apparatus and employing trained personnel. The Perkins Oil Well Cementing Company, which offers specialized oil-well cementing service in many western American oil fields, is equipped with motor trucks on each of which all of the essential apparatus is mounted and from which connections may be quickly made with the well to be cemented (see Fig. 172). Two horizontal reciprocating pumps are provided, which may be either steam driven or powered with an auxiliary internal-combustion engine. One of the two pumps is 14 by 6¾ by 12 in. in size, and the other 10 by 4½ by 10 in. They are designed to deliver cement slurry to the well under pressures as high as 3,000 lb. per square inch. The cementing equipment also includes a two-compartment tank, used in measuring the fluid pumped into the well, and a cone-jet-type cement mixer and necessary piping or armored hose for connecting the several parts of the equipment with each other and with the near-by well. The measuring tank is employed in measuring the

water used in mixing the cement and also to measure the displacement fluid pumped down through the casing after the cement. Each of the two compartments holds exactly 100 cu. ft. of fluid. Connections are provided at the well, through high-pressure steel pipe or armored hose, with a special cementing head mounted on the top of the column of casing to be cemented. Water and steam connections must also be provided with the mixing equipment. The cement to be used is placed near by in sacks. The pumps are connected with the double-compartment measuring tank, so that one pumps cement slurry, mud fluid or water into one compartment of the measuring tank while the other transfers fluid from the other compartment to the well. A conveniently arranged system of valves permits of rapidly changing the pump connections from one to the other of the two measuring compartments. One compartment of the measuring tank is thus being filled while the other is drained. The pumps may also be manifolded together in tandem, the suction line from the larger of the two pumps drawing fluid from the delivery line of the smaller pump. This



(Perkins Cementing Co., Inc.)

FIG. 172.—Well-cementing equipment permanently mounted on motor truck.

arrangement of the pumps may be used in cementing deep wells after all of the cement has entered the casing, when high pressure may be necessary to force it into position against the well friction.

The cone-jet mixer, illustrated in Fig. 173, has been patented by E. P. Halliburton. This is usually set up on the ground at one side of the truck. It is provided with a broad-mouthed hopper, into which the dry cement is dumped. The hopper tapers toward the bottom, where it connects with a horizontal pipe through which a jet of water is forced under either static or pump pressure sufficient to deliver the mixed cement slurry to the measuring tank. A record of the number of sacks of cement used and of the volume of cement slurry produced, as indicated in the measuring tank, affords an accurate check on the volume of water used and permits of close control of the percentage of water in the mix. As much as 1,000 sacks of cement can be mixed in 1 hr. with a single mixer of the cone-jet type.

A somewhat more primitive method of mixing the cement, using less elaborate equipment, is illustrated in Figs. 174 and 175. In this case, the cement is mixed by hand methods, a group of from 4 to 6 men distributed about two flat metal or wooden boxes (10 ft. long, 6 ft. wide and 2 ft. deep) stirring with hoes, while water is added

to the dry cement previously dumped into the box (see Fig. 175). Batches of cement are mixed in each box alternately. While mixing is in progress in one box, one of the

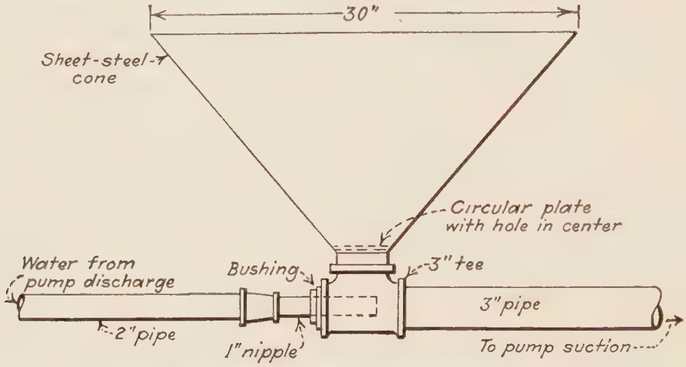
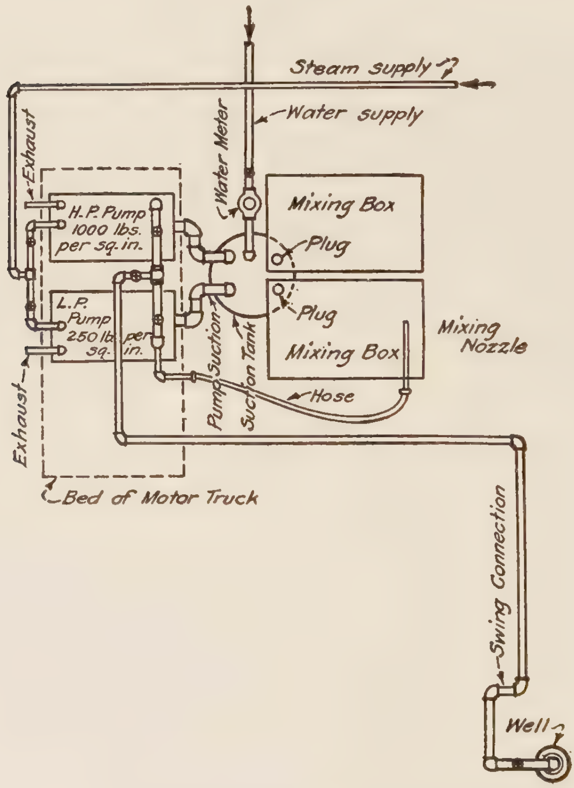


FIG. 173.—Cone and jet type of cement mixer.



(*After F. B. Tough, U. S. Bur. Mines, Bull.* 163.)

FIG. 174.—Arrangement of pumps, mixing boxes, piping, etc., for cementing wells by the Perkins process.

pumps is engaged in drawing mixed cement from the other. Either of two pumps mounted on the bed of a motor truck is used in forcing the cement into the well, one

a low-pressure pump capable of operating against a pressure of 250 lb. per square inch and the other a high-pressure pump designed to meet pressures as high as 1,000 lb. per square inch (see Fig. 174). The suction lines of the pumps are manifolded so that either may draw mixed cement from a small metal tank placed below the mixing tanks, in such a way as to receive the flow of cement from either tank when the wooden plugs controlling the discharge outlets are withdrawn. To gage the water used in mixing the cement, a water meter or a gaging tank is used. The water is passed through one of the pumps to give it sufficient pressure to permit it to be forcefully sprayed through a hose and nozzle into the dry cement in the mixing tanks. Operating systematically on a pile of dry cement, a single man is by this means able to mix the cement rapidly and thoroughly.

The mixed cement is passed ordinarily through the low-pressure pump, but, if for any reason pressures in excess of 250 lb. per square inch are necessary, the high-

Fig. 175.—Mixing cement by hand methods.

pressure pump will be brought into service. Fittings and valves on the piping connecting with the cementing head on the casing must be capable of withstanding pressures in excess of the maximum delivery pressure possible with the high-pressure pump. Connections with the well must be flexible so that the casing may be raised or lowered when necessary. A union in the delivery line near the cementing head readily permits of disconnecting the pipe to insert the wooden plugs.

The arrangements and connections at the casing head are important in permitting rapid introduction of the cementing plugs. A special quick-adjusting casing head has been designed and is widely used for this purpose. It embodies three drive-up slips and a cylindrical rubber packing ring which can be expanded against the inside surface of the casing by turning an adjusting collar on a square thread. It is so constructed that upward pressure against the base assists in expanding the rubber packer and causes the slips to grip the casing more securely. This head is secure against very high pressures and yet can be quickly detached and reinserted. It can be disengaged from the casing without disturbing the connection to the cement pumps.

Another device in the form of a steel capsule, connected in a vertical position above the casing head, affords a means of introducing the Perkins plugs at any desired point

in the fluid stream entering the casing, without breaking any pipe connections and with only momentary interruption in pumping. The plugs are held in place in the steel capsule, one above the other, with the first plug to enter the casing below the second. Each is held in position by a set screw penetrating the steel wall of the container. After mud circulation has proceeded for a time and the pump is about to introduce the cement, the cap screw controlling the lower plug is loosened allowing the plug to fall into the casing. Later, when all of the cement has entered the casing and the pump suction is again changed to water or mud fluid, the second plug is released.

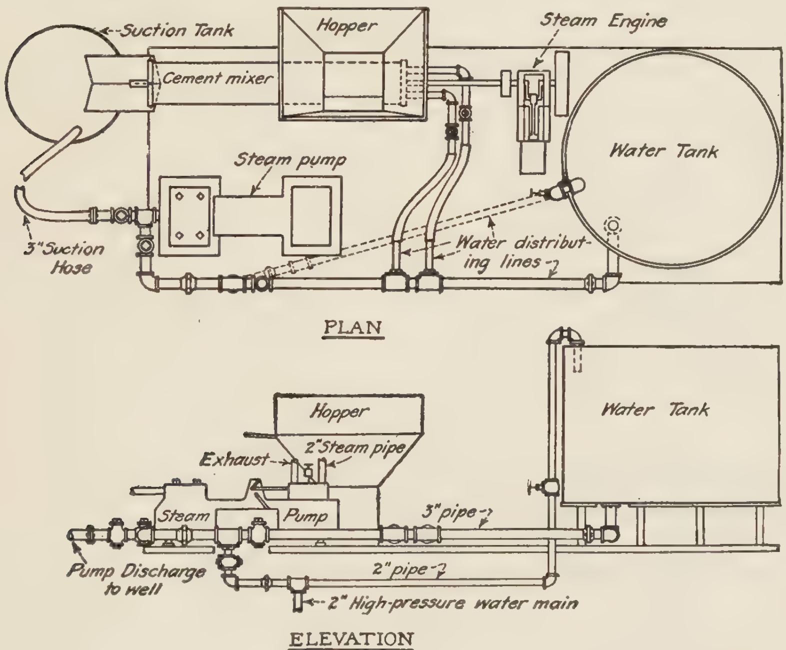
The lower end of the column of casing is held about 1 ft. off bottom during the introduction of the cement, unless a float shoe having side outlets is used on the lower end of the casing (see page 288). In the latter case, the column of pipe may rest on bottom. Except in the case of unusually long strings, some authorities recommend moving the casing up and down through a distance equal to the length of a joint of casing after a part of the cement has been displaced from the casing. It is believed that this practice assists in preventing channeling of cement through accumulated mud about the pipe. The lower end of the casing should be held near bottom, however, until a considerable column of cement has accumulated about the pipe, otherwise there is likelihood of mud occlusion when the column of pipe is subsequently lowered.

As the cement is pumped into the casing, being denser than the well fluid, it tends to sink into and displace the latter, so that very little pump pressure is necessary. This effect, however, gradually diminishes as the work proceeds, until equilibrium is established and the pump pressure must then be gradually increased. Pressures of many hundreds of pounds are sometimes reached in deep wells before the cement is entirely displaced from the casing. When the last of the cement has entered the casing, it should be pumped down as rapidly as possible. The slush pumps may be used for this purpose, if the well is being drilled by the rotary method, and a heavy mud fluid is often used to follow the cement after the second plug has entered the casing in order that its hydrostatic pressure may assist the pumps in overcoming the well resistance.

When the two Perkins plugs come together on the casing float shoe or, if one is used, on the baffle plate near the lower end of the casing, there will be a sudden increase in pressure, perhaps stalling the pumps, indicating satisfactory completion of the work. While, if all goes well, the operator may depend upon the action of the plugs and pumps to indicate when all cement has passed out of the casing, it is a good precaution to have some means of checking the progress of operations that may be relied upon to indicate the position of the upper plug in the event that something goes wrong. Possible accidents that may prevent orderly completion of the work include caving of the walls of the well, cutting off of circulation, splitting or parting of the casing, "hanging up" of the plugs as a result of some obstruction in the casing or failure of the washers on the upper plug to hold against the pump pressure. As a precaution it is customary to calculate the volume of the casing, and an equivalent volume of water or mud fluid is used to displace the cement. The fluid so used should be carefully gaged or metered, or a rough computation of the fluid volume may be obtained, if the displacement of the pump is known, by counting the number of strokes. A device patented by E. P. Halliburton affords a more positive means of determining the position of the top plug. It consists of a measuring line and bob, which is lowered through a stuffing box on the cement head, and a suitable reel and recording sheave. The bob is lowered on the measuring line as the upper cement plug moves down the casing and shows at all times its exact depth.

There has been considerable discussion concerning whether or not air finds its way into the cement about the casing shoe when the Perkins system is used. Owing to the greater density of the cement slurry, in comparison with that of the well fluid, it often continues moving down the casing when the cementing head is opened to admit

the upper plug so that, when the latter is inserted, a body of air is trapped above the cement. As this air is pumped down the casing, it will be eventually forced through the lower plug and out into the well, possibly forming voids in the cement at the critical point about the casing shoe. A plug capsule for the upper plug, as described above, prevents admission of air to the casing and is used by some operators primarily for this reason. Another method of avoiding air pockets in the lower part of the cement plug is to leave some of the cement in the casing. This may be done by placing a perforated baffle plate in the casing one or two joints above bottom, thus stopping the two plugs at this point. Another method allows the lower plug to proceed to the valve in the casing float shoe but uses a "spacer" in the form of a 2- by 4-in. or 4- by



(*After F. B. Tough, U. S. Bur. Mines, Bull.* 163.)

FIG. 176.—Scott cementing apparatus.

4-in. timber about 20 ft. long between the two plugs. Or, the Halliburton measuring line permits of stopping the upper plug at any desired point. By either of these methods, the latter part of the cement, which is likely to contain air, is retained within the casing, later to be drilled out with the tools. Another reason for leaving some of the cement in the casing, is found in the tendency of the cement to settle, thus leaving the upper portion of the cement column within the casing very dilute, consisting perhaps chiefly of water. Sometimes, too, the upper part of the cement column becomes diluted with mud, owing to leakage past the upper plug. Cores taken of the cement left inside the casing after cementing show that it lacks strength and hardness. Usually operations are planned to leave at least 25 ft. of cement in the casing. Some operators recommend 10 ft. for each 1,000 ft. of depth.

The Scott Cementing Apparatus.—Cement equipment designed and used by W. F. Scott in the California fields is illustrated in Fig. 176. It consists of a mechanically driven cement mixer, comprising a hopper into which the cement is dumped and a

tubular mixing barrel in which it is mixed with water by the action of revolving blades mounted on a longitudinally placed steel shaft.[22] A small steam engine supplies the necessary power. Water flows into this mixing barrel from a large gaging tank. The cement flows from the mixer into a small cylindrical tank, from which it is taken into the suction line of a steam-driven reciprocating pump and pumped into the well. A suitable manifold and valve control on the pump suction line makes it possible to pump water from the storage tank directly to the well when desired. The entire apparatus may be mounted on a motor truck or wagon. Outfits of this type operated by Scott are able to mix 1 ton of cement in from 2½ to 3 min.

Scott has also developed and successfully applied methods of cementing through tubing and casing without barriers. In preparation for cementing operations, the equipment as described above is set up near the well and connections made with the local steam and water lines and from the pump to a cementing head placed on the casing. If the well is a deep one, it may be necessary to provide a larger water storage tank than the one which is commonly carried with the outfit. The tank should be large enough to contain water sufficient for mixing the cement, and to fill the tubing or casing used in conducting the cement with an excess of at least 10 per cent. Since the mixing machine works very rapidly, one sack of cement being mixed every 8 or 9 sec., the sacks should be opened before mixing is begun and placed on or near a platform built around the hopper of the mixing machine. The work of feeding the machine is tiring and four men should be provided to handle the cement, two working at a time and relieving each other frequently. Before the work is begun, computations are made of the volume of the tubing or casing through which the cement is pumped, and the equivalent, expressed in inches of depth of the water storage tank, is determined.

With all in readiness, circulation is first established through the well, the cement mixer is placed in operation, and as the mixed cement is made available to the pump suction, the manifold valves are manipulated so that cement is pumped into the well without interruption in circulation. After all the cement has passed through the pump, reversal of the valves connects the pump suction with the water supply, again without interruption in circulation. The pump works continuously from the start of operations until the casing is lowered to bottom. If the tubing method is employed, as explained on page 358, the pumps may continue in operation after the casing is landed until any excess cement which may be left between the tubing and the casing is returned to the surface.

Other methods of mixing cement have been used with more or less success. A California operator has employed an ordinary cement mixer, such as is used in mixing cement for building and road construction. The cement flows from the mixer into a wooden trough, where it is given further mixing by men equipped with hoes. The steam pumps, mounted on a wagon, pass the mixed cement under pressure from the lower end of the trough to the well. Some operators use the pumps to aid in mixing, a hose on the discharge manifold returning the cement to the mixing box from which the pump suction draws its supply. When this method is employed, all of the cement must be mixed before any is pumped into the well.

Planning a Cementing "Job"

Before the exclusion of water is attempted in a well, the work should be carefully planned in order to insure its successful completion. The landing depth for the shoe of the water string must be selected so that it will rest in a stratum impervious to the passage of water. The desirable length for the cement plug should be determined, and the necessary

amount of cement calculated to form a plug of this length for the size of casing in use and in the size of hole drilled. The physical conditions to be encountered should be carefully studied. Important factors to consider include the temperature at the depth where the cement is to be placed; the possibility of contamination of the cement with saline ground water before setting, or of it being subjected to agitation by strong flows of gas or water during the setting period; the condition of the bottom of the hole and of the casing; and whether or not it is possible to establish circulation between the casing and the walls of the well by the application of pressures within reach of the pumping equipment available. If any one of these factors is unfavorable, it may defeat the purpose of the work unless its influence is considered and preparations are made to counteract it at the proper time.

Table XXXVI.—Volume Occupied by a Sack (94 lb.) of Cement for Various Water-cement Ratios*

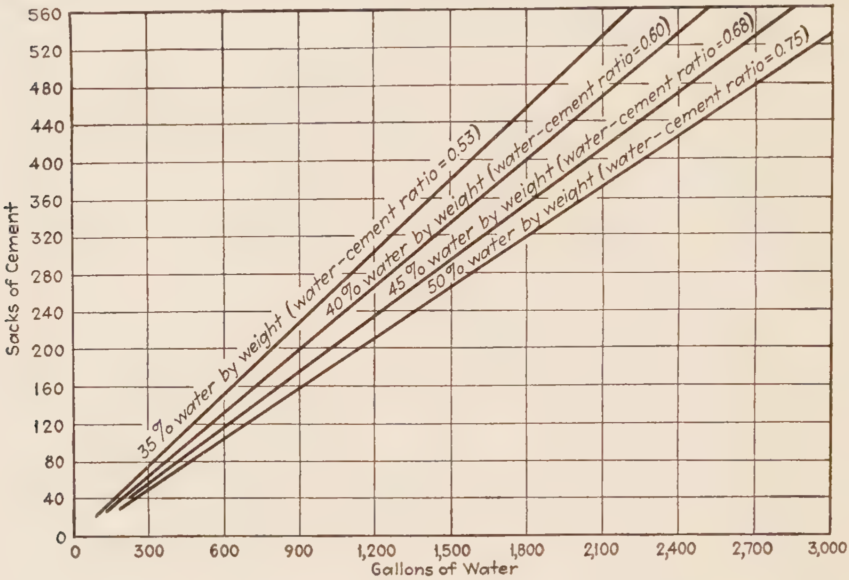
Water-cement Ratio		Volume cu. ft.	
Gal. per sack	Per cent by weight	By actual experiment, cu. ft.	Theoretical volume based on absolute volume of 0.484 cu. ft. per sack, cu. ft.
3	26.5	.96	1.00
3½	30.9	.94	1.00
4	35.3	1.01	1.012
4½	39.7	1.06	1.085
5	44.1	1.13	1.145
5½	48.6	1.24	1.209
6	53.0	1.32	1.283
6½	57.4	1.39	1.342
7	61.8	1.46	1.411
7½	66.2	1.50	1.475

* After W. T. Doherty and M. Manning.

A sample of the cement to be used should be tested to determine its setting time and soundness. If possible, a sample of the well fluid from a point near the proposed shut-off should be secured, and used in mixing the cement slurry to determine the influence of any dissolved salt, which may be present, on the setting time.

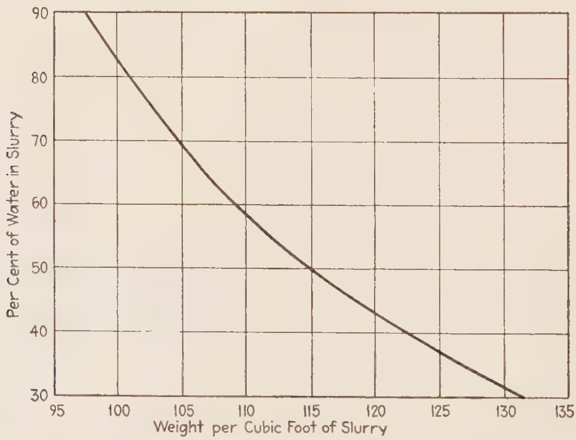
In calculating the amount of cement necessary, it is well to assume that the cement plug will extend entirely through the water sand to be cased off and preferably to some distance above. If analysis of the waters in the sands above the point selected for the shut-off shows that they contain salts which will have a corrosive effect on the casing, it will be advisable to protect the pipe from them by forming a long sheathing of cement about it. In such cases enough cement may be introduced to

form a plug many hundreds of feet long. In some instances the entire space back of the pipe up to the surface has been filled with cement, with the purpose of protecting the casing against rapid corrosion. Having



(*After Doherty and Manning.*)

FIG. 177.—Graphs showing amounts of water and cement necessary to form slurries of various percentages water content.

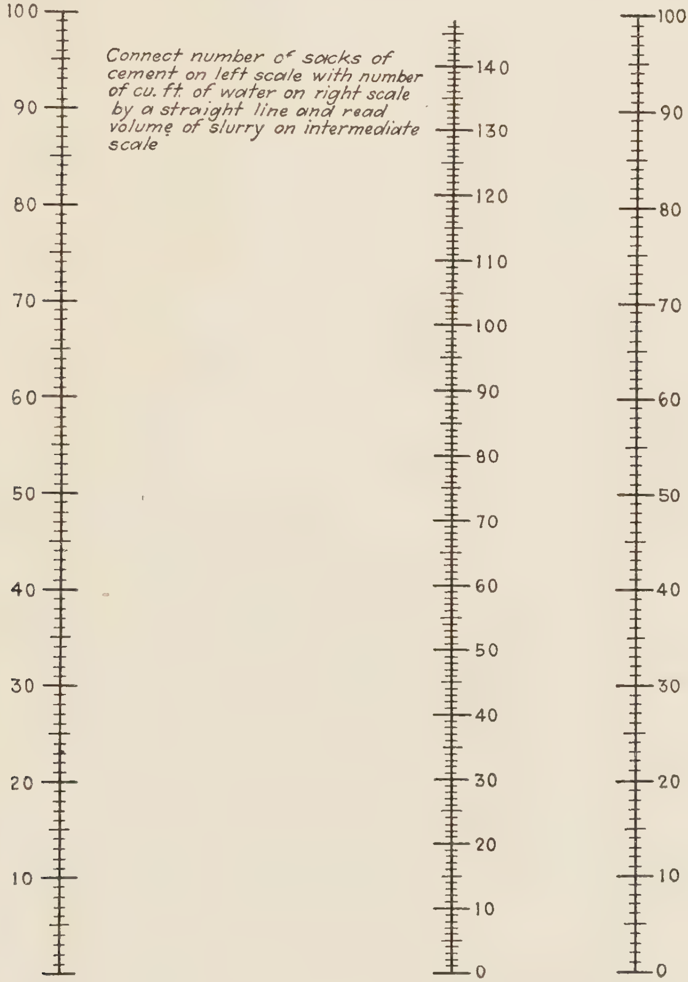


(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 178.—Graph showing variation of weight of neat cement slurry with percentage of water used.

determined the necessary length of plug to provide, and knowing the size of the casing and the diameter of the well, the volume of the cement plug to be formed is calculated.

It is convenient, in planning cementing operations, to have in mind certain constants expressing the relations existing between the weights and volumes of cement mixtures, and to have access to tables which simplify the work of calculating volumes to be filled. Portland cement varies somewhat in density, ranging from 3.10 to 3.23.



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 179.—Alignment chart for estimating volume of cement slurry formed by different mixtures of water and cement.

A sack of cement weighing 94 lb. is estimated to have an absolute volume of 0.484 cu. ft., or 829.44 cu. in. This represents the volume of the material less that of the pore space occluded within it. When mixed with water, the volume of the mixture will depend upon the percentage of water used in the mix, as shown by Table XXXVI.

In cement terminology the percentage of water referred to is always a percentage of the weight of the cement—not a percentage of the weight of the mixture. Thus, a 50 per cent slurry contains 50 lb. of water for each 100 lb. of dry cement. The percentage of water used in mixtures pumped into wells ranges from 35 to 50 per cent of

TABLE XXXVII.—AMOUNT OF CEMENT NECESSARY TO FORM CEMENT PLUGS ABOUT CASINGS OF VARIOUS SIZES IN WELLS OF DIFFERENT DIAMETERS*†

Style	Outside diameter, in.	Weight per foot complete	Casing diameter		Number of sacks of neat cement to fill 100 lin. ft., outside various strings of casing in various holes																									Number of sacks of neat cement to fill 100 lin. ft. on the inside of casing
					Diameter of hole in.																									
			External	Internal	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
A.P.I.	4¾	16	4.750	4.082	7	13	20	29	39	48	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	8
Non A.P.I.	5	15	5.000	4.408	5	12	19	28	37	48	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	10
Non A.P.I.	5	18	5.000	4.276	5	12	19	28	37	48	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	9
Non A.P.I.	5	21	5.000	4.154	5	12	19	28	37	48	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	9
Non A.P.I.	5½	17	5.500	4.892	...	9	17	25	35	46	56	67	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	12
Non A.P.I.	5½	20	5.500	4.778	...	9	17	25	35	46	56	67	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	11
A.P.I.	5¾	14	5.750	5.290	...	8	15	24	33	44	56	67	83	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	14
A.P.I.	5¾	17	5.750	5.190	...	8	15	24	33	44	56	67	83	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	13
A.P.I.	5¾	19.5	5.750	5.090	...	8	15	24	33	44	56	67	83	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	13
A.P.I.	5¾	22.5	5.750	4.990	...	8	15	24	33	44	56	67	83	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	12
A.P.I.	6⅝	20	6.625	6.049	...	...	10	19	28	39	50	63	77	91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	18
A.P.I.	6⅝	24	6.625	5.921	...	...	10	19	28	39	50	63	77	91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	17
A.P.I.	6⅝	26	6.625	5.855	...	...	10	19	28	39	50	63	77	91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	17
A.P.I.	6⅝	28	6.626	5.791	...	...	10	19	28	39	50	63	77	91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	17
A.P.I.	7	20	7.000	6.456	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	21
A.P.I.	7	22	7.000	6.398	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	20
A.P.I.	7	24	7.000	6.336	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	20
A.P.I.	7	26	7.000	6.276	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	20
A.P.I.	7	28	7.000	6.214	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	19
A.P.I.	7	30	7.000	6.154	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	19
Non A.P.I.	7	43	7.000	5.736	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	16
A.P.I.	7⅝	26.40	7.625	6.969	...	...	...	11	21	31	42	56	67	84	100	111	...	...	...	...	...	...	...	...	...	...	...	...	...	24
A.P.I.	7⅝	29.70	7.625	6.875	...	...	...	11	21	31	42	56	67	84	100	111	...	...	...	...	...	...	...	...	...	...	...	...	...	24
A.P.I.	7⅝	33.70	7.625	6.765	...	...	...	11	21	31	42	56	67	84	100	111	...	...	...	...	...	...	...	...	...	...	...	...	...	23
A.P.I.	8⅛	28	8.125	7.485	...	...	...	...	17	22	39	50	63	77	91	111	...	...	...	...	...	...	...	...	...	...	...	...	...	28
A.P.I.	8⅛	32	8.125	7.385	...	...	...	...	17	22	39	50	63	77	91	111	...	...	...	...	...	...	...	...	...	...	...	...	...	27
A.P.I.	8⅛	35.5	8.125	7.285	...	...	...	...	17	22	39	50	63	77	91	111	...	...	...	...	...	...	...	...	...	...	...	...	...	26
A.P.I.	8⅛	39.5	8.125	7.185	...	...	...	...	17	22	39	50	63	77	91	111	...	...	...	...	...	...	...	...	...	...	...	...	...	26
A.P.I.	8⅝	28	8.625	8.017	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	32
A.P.I.	8⅝	32	8.625	7.921	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	31
A.P.I.	8⅝	36	8.625	7.825	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	30

A.P.I.	8⅝	38	8.625	7.775	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	29
A.P.I.	8⅝	43	8.625	7.651	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	29
A.P.I.	9	34	9.000	8.290	...	...	...	...	...	20	31	44	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	...	34
A.P.I.	9	38	9.000	8.196	...	...	...	...	...	20	31	44	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	...	33
A.P.I.	9	40	9.000	8.150	...	...	...	...	...	20	31	44	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	...	32
A.P.I.	9	45	9.000	8.032	...	...	...	...	...	20	31	44	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	...	31
A.P.I.	9⅝	36	9.625	8.921	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	40
Non A.P.I.	9⅝	38	9.625	8.885	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	40
A.P.I.	9⅝	40	9.625	8.835	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	38
Non A.P.I.	9⅝	42	9.625	8.799	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	38
A.P.I.	9⅝	43.5	9.625	8.755	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	37
A.P.I.	10¾	40.5	10.750	10.050	...	...	...	...	...	...	14	26	40	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	50
A.P.I.	10¾	45.5	10.750	9.950	...	...	...	...	...	...	14	26	40	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	48
A.P.I.	10¾	51	10.750	9.850	...	...	...	...	...	...	14	26	40	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	48
A.P.I.	10¾	55.5	10.750	9.760	...	...	...	...	...	...	14	26	40	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	48
A.P.I.	11¾	47	11.750	11.000	...	...	...	...	...	...	...	15	29	44	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	59
A.P.I.	11¾	54	11.750	10.880	...	...	...	...	...	...	...	15	29	44	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	59
A.P.I.	11¾	60	11.750	10.772	...	...	...	...	...	...	...	15	29	44	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	59
Non A.P.I.	13	40	13.000	12.438	...	...	...	...	...	...	...	...	...	28	44	59	77	91	111	143	...	...	...	...	...	...	...	...	...	77
Non A.P.I.	13	45	13.000	12.360	...	...	...	...	...	...	...	...	...	28	44	59	77	91	111	143	...	...	...	...	...	...	...	...	...	77
Non A.P.I.	13	50	13.000	12.282	...	...	...	...	...	...	...	...	...	28	44	59	77	91	111	143	...	...	...	...	...	...	...	...	...	77
Non A.P.I.	13	54	13.000	12.220	...	...	...	...	...	...	...	...	...	28	44	59	77	91	111	143	...	...	...	...	...	...	...	...	...	71
A.P.I.	13⅜	48	13.375	12.715	...	...	...	...	...	...	...	...	...	23	39	56	71	91	111	125	143	...	...	...	...	...	...	...	...	83
A.P.I.	13⅜	54.5	13.375	12.615	...	...	...	...	...	...	...	...	...	23	39	56	71	91	111	125	143	...	...	...	...	...	...	...	...	77
A.P.I.	13⅜	61	13.375	12.515	...	...	...	...	...	...	...	...	...	23	39	56	71	91	111	125	143	...	...	...	...	...	...	...	...	77
A.P.I.	13⅜	68	13.375	12.415	...	...	...	...	...	...	...	...	...	23	39	56	71	91	111	125	143	...	...	...	...	...	...	...	...	77
A.P.I.	16	55	16.000	15.375	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
A.P.I.	16	65	16.000	15.250	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
Non A.P.I.	16	70	16.000	15.198	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
A.P.I.	16	75	16.000	15.125	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
A.P.I.	16	84	16.000	15.010	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
A.P.I.	18⅝	78	18.625	17.855	...	...	...	...	...	...	...	...	...	...	...	...	...	...	26	48	67	91	111	143	...	...	...	...	...	167
A.P.I.	18⅝	87.5	18 625	17.755	...	...	...	...	...	...	...	...	...	...	...	...	...	...	26	48	67	91	111	143	...	...	...	...	...	167
A.P.I.	18⅝	96.5	18.625	17.655	...	...	...	...	...	...	...	...	...	...	...	...	...	...	26	48	67	91	111	143	...	...	...	...	...	167
Non A.P.I.	20	90	20.000	19.190	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	42	63	91	111	143	167	...	...	...	200
A.P.I.	21½	92.5	21.500	20.710	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	33	56	83	111	125	167	...	...	200
A.P.I.	21½	103	21.500	20.610	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	33	56	83	111	125	167	...	...	200
A.P.I.	21½	114	21.500	20.510	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	33	56	83	111	125	167	...	...	200
A.P.I.	24½	100.5	24.500	23.750	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	37	63	91	125	143	250
A.P.I.	24½	113	24.500	23.650	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	37	63	91	125	143	250

NOTE:—The above are theoretical figures, no allowance being made for variations in size of hole.

* Courtesy of Spang, Chalfant and Company, Inc., Pittsburgh, Pa.

† Calculations based on assumption that one sack of neat cement, after setting, fills 1 1 cu. ft.

TABLE XXXVIII.—VOLUMETRIC CAPACITIES OF TUBING AND CASINGS OF DIFFERENT WEIGHTS AND SIZES*

Style	Nominal size, in.	Weight per foot complete	Tubing diameters		Capacity bbl. per 100 ft.	Capacity lin. ft. per barrel
			External	Internal		
†A.P.I.	1¼	2.40	1.660	1.380	.185	540.540
†A.P.I.	1½	2.90	1.900	1.610	.252	398.050
A.P.I.	2	4.60	2.375	1.995	.387	258.650
†A.P.I.	2	4.70	2.375	1.995	.387	258.650
A.P.I.	2½	6.40	2.875	2.441	.579	172.760
†A.P.I.	2½	6.50	2.875	2.441	.579	172.760
A.P.I.	3	9.20	3.500	2.992	.870	114.990
†A.P.I.	3	9.30	3.500	2.992	.870	114.990
A.P.I.	3	10.20	3.500	2.922	.829	120.570
A.P.I.	3½	9.50	4.000	3.548	1.223	81.777
†A.P.I.	3½	11.00	4.000	3.476	1.174	85.198
A.P.I.	4	12.60	4.500	3.958	1.522	65.710
†A.P.I.	4	12.75	4.500	3.958	1.522	65.710

Style	Outside diameter, in.	Weight per foot complete	Casing diameters		Capacity bbl. per 100 ft.	Capacity lin. ft. per barrel
			External	Internal		
A.P.I.	4¾	16.00	4.750	4.082	1.618	61.794
Non A.P.I.	5	15.00	5.000	4.408	1.888	52.980
Non A.P.I.	5	18.00	5.000	4.276	1.776	56.300
Non A.P.I.	5	21.00	5.000	4.154	1.676	59.656
Non A.P.I.	5½	17.00	5.500	4.892	2.325	43.014
Non A.P.I.	5½	20.00	5.500	4.778	2.218	45.091
A.P.I.	5¾	14.00	5.750	5.290	2.719	36.785
A.P.I.	5¾	17.00	5.750	5.190	2.617	38.216
A.P.I.	5¾	19.50	5.750	5.090	2.517	39.733
A.P.I.	5¾	22.50	5.750	4.990	2.419	41.342

Style	Outside diameter, in.	Weight per foot complete	Casing diameters		Capacity bbl. per 100 ft.	Capacity lin. ft. per barrel
			External	Internal		
A.P.I.	6⅝	20.00	6.625	6.049	3.554	28.134
A.P.I.	6⅝	24.00	6.625	5.921	3.406	29.362
A.P.I.	6⅝	26.00	6.625	5.855	3.330	30.028
A.P.I.	6⅝	28.00	6.625	5.791	3.258	30.697
A.P.I.	7	20.00	7.000	6.456	4.049	24.698
A.P.I.	7	22.00	7.000	6.398	3.976	25.148
A.P.I.	7	24.00	7.000	6.336	3.900	25.589
A.P.I.	7	26.00	7.000	6.276	3.826	26.135
A.P.I.	7	28.00	7.000	6.214	3.751	26.660
A.P.I.	7	30.00	7.000	6.154	3.679	27.181
Non A.P.I.	7	43.00	7.000	5.736	3.196	31.287
A.P.I.	7⅝	26.40	7.625	6.969	4.718	21.196
A.P.I.	7⅝	29.70	7.625	6.875	4.591	21.780
A.P.I.	7⅝	33.70	7.625	6.765	4.446	22.493
A.P.I.	8⅛	28.00	8.125	7.485	5.442	18.374
A.P.I.	8⅛	32.00	8.125	7.385	5.298	18.875
A.P.I.	8⅛	35.50	8.125	7.285	5.156	19.397
A.P.I.	8⅛	39.50	8.125	7.185	5.015	19.940
A.P.I.	8⅝	28.00	8.625	8.017	6.244	16.017
A.P.I.	8⅝	32.00	8.625	7.921	6.095	16.407
A.P.I.	8⅝	36.00	8.625	7.825	5.948	16.812
A.P.I.	8⅝	38.00	8.625	7.775	5.872	17.029
A.P.I.	8⅝	43.00	8.625	7.651	5.687	17.585
A.P.I.	9	34.00	9.000	8.290	6.676	14.980
A.P.I.	9	38.00	9.000	8.196	6.525	15.325
A.P.I.	9	40.00	9.000	8.150	6.453	15.498
A.P.I.	9	45.00	9.000	8.032	6.267	15.957
A.P.I.	9⅝	36.00	9.625	8.921	7.731	12.935
Non A.P.I.	9⅝	38.00	9.625	8.885	7.669	13.040
A.P.I.	9⅝	40.00	9.625	8.835	7.583	13.188
Non A.P.I.	9⅝	42.00	9.625	8.799	7.521	13.296
A.P.I.	9⅝	43.50	9.625	8.755	7.446	13.430

Style	Outside diameter, in.	Weight per foot complete	Casing diameters		Capacity bbl. per 100 ft.	Capacity lin. ft. per barrel
			External	Internal		
A.P.I.	10¾	40.50	10.750	10.050	9.812	10.192
A.P.I.	10¾	45.50	10.750	9.950	9.617	10.398
A.P.I.	10¾	51.00	10.750	9.850	9.425	10.610
A.P.I.	10¾	55.50	10.750	9.760	9.254	10.807
A.P.I.	11¾	47.00	11.750	11.000	11.754	8.508
A.P.I.	11¾	54.00	11.750	10.880	11.499	8.696
A.P.I.	11¾	60.00	11.750	10.772	11.272	8.871
Non A.P.I.	13	40.00	13.000	12.438	15.028	6.654
Non A.P.I.	13	45.00	13.000	12.360	14.841	6.738
Non A.P.I.	13	50.00	13.000	12.282	14.654	6.824
Non A.P.I.	13	54.00	13.000	12.220	14.506	6.894
A.P.I.	13⅜	48.00	13.375	12.715	15.705	6.367
A.P.I.	13⅜	54.50	13.375	12.615	15.459	6.469
A.P.I.	13⅜	61.00	13.375	12.515	15.215	6.573
A.P.I.	13⅜	68.00	13.375	12.415	14.973	6.679
A.P.I.	16	55.00	16.000	15.375	22.964	4.355
A.P.I.	16	65.00	16.000	15.250	22.592	4.426
Non A.P.I.	16	70.00	16.000	15.198	22.437	4.457
A.P.I.	16	75.00	16.000	15.125	22.224	4.500
A.P.I.	16	84.00	16.000	15.010	21.886	4.569
A.P.I.	18⅝	78.00	18.625	17.855	30.969	3.229
A.P.I.	18⅝	87.50	18.625	17.755	30.626	3.265
A.P.I.	18⅝	96.50	18.625	17.655	30.279	3.303
Non A.P.I.	20	90.00	20.00	19.190	35.773	2.795
A.P.I.	21½	92.50	21.500	20.710	41.665	2.400
A.P.I.	21½	103.00	21.500	20.610	41.264	2.424
A.P.I.	21½	114.00	21.500	20.510	40.865	2.447
A.P.I.	24½	100.50	24.500	23.750	54.794	1.825
A.P.I.	24½	113.00	24.500	23.650	54.334	1.841

* Courtesy of Spang, Chalfant & Co., Inc., Pittsburgh, Pa.
† Upset tubing.

the weight of the dry cement. A mixture having a water-to-cement ratio, by weight, of about 42 per cent (4.75 gal. per sack), is probably a good average of the mixtures used. As indicated in Table XXXVI, a sack of cement mixed with water in this ratio would occupy about 1.1 cu. ft. This is a convenient average figure to use in computations to determine the number of sacks of cement necessary to fill a required space. Using this volume per sack, Table XXXVII has been prepared to show the number of sacks necessary per 100 lin. ft. of depth, to fill the space between casings of different sizes and weights and the walls of wells of different diameters. Table XXXVIII will also be found useful in estimating volumes of casings. The graphs of Figs. 177, 178 and 179 are convenient in determining the quantities of cement and water necessary to produce slurries of different volumes, densities and percentage of water content.

A convenient formula for computing the quantity of cement necessary for a given set of conditions, where a neat-cement plug is to be formed in a well about the lower end of a column of casing, is that proposed by Scott*:

$$Q = \frac{F \times (d_1^2 - d^2) \times 0.005454}{1.1}.$$

In this formula F is the number of linear feet to be filled in the annular space outside of the casing: d_1 is the diameter of the hole in inches; d is the outside diameter of the casing in inches; and Q is the number of sacks of cement required.

The amount of cement necessary to fill a well or a column of casing for a given number of linear feet is found by the expression

$$Q = \frac{0.005454d^2 \times F}{1.1}.$$

In this formula d is the diameter of the well or the inside diameter of the casing to be filled and F the number of linear feet to be filled.

Table XXXIX.—Data on Typical Cementing Operations in the California Fields*

Size of casing, in.	Average length of string, ft.	Average amount of cement, sacks	Average time of displacement, min.	Average final pump pressure, lb. per sq. in.	Maximum casing length, ft.
6⅝	4,604	110	35.5	730	6,668
8⅝	4,886	318	38.5	830	5,934
9	3,282	330	36	625	5,679
11¾	3,107	410	45	614	4,714
13⅜	3,141	385	40	558	4,195

* Data collected by a committee of California operators and cement contractors.

The amount of cement used in a cementing job will depend chiefly upon the size of the casing. Table XXXIX shows the average quantities of cement used in 183 different cementing operations on different sizes of casing in the California fields. It will be seen that the quantity of cement used increases with the diameter of the casing and that the time occupied in displacing the cement from the casing ranges from 35 to 45 min. Average final pump pressures range from 550 to upward of 800 lb. As many as 2,000 sacks of cement are used in some cases where large diameter casings are to be cemented and unusually long plugs must be formed.

* Scott, B. H., Difficult Conditions Met by Modern Cementing Systems, *Oil Field Engineering*, October, 1928, pp. 23–31.

Use of Hydraulic Lime in Excluding Water from Wells.—Occasionally it will be necessary to cement a well against the pressure of a strong flow of high-pressure water or gas. Perhaps there is only one string of casing in the well and it is impossible to close it in or to apply pump pressure. It may happen that mudding to "kill" the pressure is ineffective because the formation absorbs the well fluid and makes it impossible to secure circulation. In such a case the operator may resort to the use of hydraulic lime as a means of sealing the walls and excluding the high-pressure gas and water, so that Portland cement later introduced may rest undisturbed during its setting period.[22]

Hydraulic lime is manufactured by burning and hydrating lime rock, but the material is not sintered as in the case of Portland cement. Table XXXV gives characteristic analyses. The calcium and magnesium are left in the hydrated form as $Ca(OH)_2$ or $Mg(OH)_2$ but contain no water of crystallization. Unlike ordinary lime, hydraulic lime will set under water.

When hydraulic lime comes into contact with finely divided silica and the aluminum silicates of shales and clays, it reacts to form complex gelatinous silicates which expand in hardening and fill the rock pores. By forcing it under pressure into a well, we thus convert the mud, which lines the rock walls, into a hard impervious sheathing, locked to the walls by penetration into rock pores and crevices in such a way as effectively to resist passage of fluids into the well.

In the practical application of hydraulic lime in excluding flowing water and preparing the well for a plug of Portland cement, the lime is mixed separately with water and pumped into the well ahead of the cement.[22] The cement follows immediately behind the lime solution which combines with the clay to form a gelatinous adherent coating on the walls of the well so that they present a well-consolidated surface to the cement. As a result, there is little tendency for the clay in the walls to dilute the cement, and the conditions for setting of the cement without agitation by high-pressure flowing water or gas are more favorable.

Hydraulic lime may also be used effectively in rotary drilling by admixture with the mud-laden fluid, in sealing dry or low-pressure sands which absorb the well fluid to such a degree that circulation is difficult or impossible.

EXCLUSION OF WATER FROM WELLS BY MUDDING

The action of circulating mud-laden fluid under pressure in closing the pores of granular rocks has already been discussed in connection with rotary drilling. Use of mud in this way has also been successfully applied in the permanent exclusion of water as a substitute for the cementing process.

In one instance described by A. W. Ambrose,* a well in the Coalinga field of California was drilled to produce from the lower of two oil sands, between which there is an intermediate water sand. The well was drilled through both the upper oil sand and the intermediate water sand before any cement was placed, security against admission of water into the upper oil sand being assured by a thorough mudding of the oil and water sands while drilling through them with rotary tools. By this method a string of casing costing $6,000 was saved. When the cement was placed to protect the lower oil sand, sufficient was used to form a plug extending up through the upper oil sand. A near-by well, only 150 ft. distant, producing from the upper sand, provided a means of testing the efficacy of the mud. For a time, while mudding was in process, the near-by well produced considerable quantities of muddy water, but flow between the two wells ceased before the process was completed.

In the development of certain California fields, where upper oil and gas strata are cased off behind a water string to obtain production from more productive lower zones, it has become the custom for operators thoroughly to mud the upper formations under pressure in order to prevent intermingling of fluids from different beds above the shut-off. This practice saves one or more strings of pipe that must otherwise be cemented between the several zones and gives ample protection to operators producing from the upper beds. Many hundreds of wells have been so treated in the California fields and the records of the State Oil and Gas Supervisor's Department show that in upward of 85 per cent of the wells the mudding has apparently accomplished its purpose.†

The mudding process may be conducted through casing or rotary drill pipe by continued circulation as in rotary drilling; or by using a circulating head and throttling the outlet, an additional pump pressure of several hundred pounds may be held on the well while the fluid is circulated (see Fig. 180). Circulation is usually down through the casing or drill pipe and back to the surface between the pipe and the walls of the well; but in some cases it has been found advantageous to reverse the direction, pumping down through the annular space between the conductor string and the inner pipe.‡

Some operators recommend mudding under a pump pressure of from 200 to 300 lb. per square inch, continuing circulation until the formation absorbs less than 2 bbl. of fluid per hour. This is not always possible, though in many cases the volume of fluid absorbed has been reduced to less than 1 bbl. per hour. This condition is often reached after 10 hr. of continual circulation under pressure but in extreme cases may require a week or more. It should be pointed out in this connection that the quantity of fluid absorbed by the formation will vary with the wall area exposed, that is, with the depth or thickness of exposed rock face and the diameter of the well. Absorption

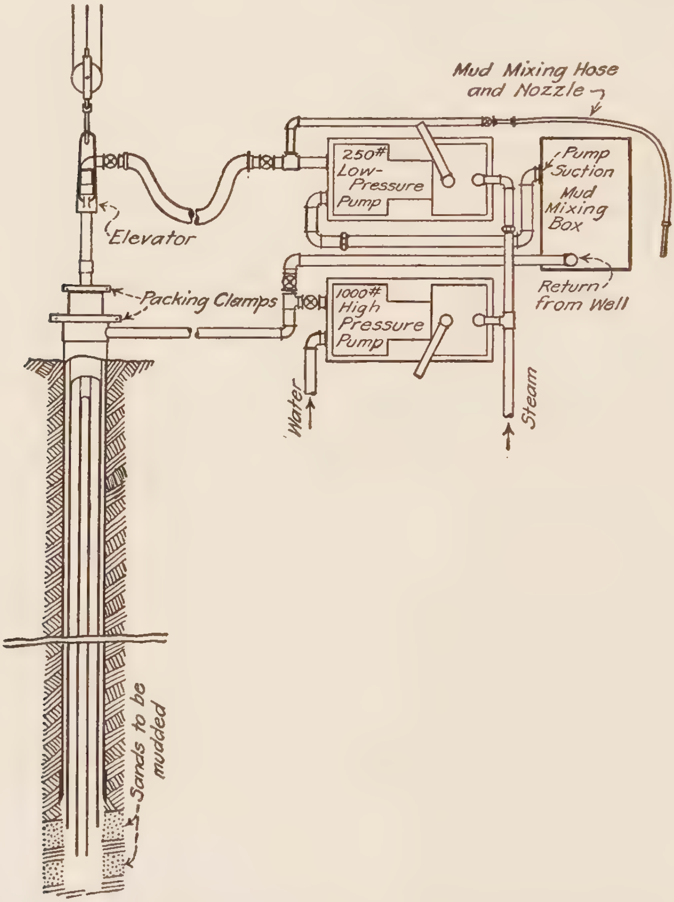
* U. S. Bur. Mines, *Bull.* 195, p. 157.

† Collom, R. E., Mud Fluid for Rotary Drilling, *Summary of Operations, California Oil Fields*, vol. 8, no. 7, January, 1923. (With a report on the use of mud-laden fluid in the California fields by a special committee of engineers.)

‡ See References 15, 16 and 17 at end of Chap. XI.

and the degree of penetration obtained will also vary with the permeability of the beds penetrated and with the pressure of the fluids stored within them.

A more effective mudding action of the circulating fluid may be secured by the addition of substances which serve as coagulants for the clay particles. As explained in the preceding section, hydraulic lime may be effectively used for this purpose, forming a sticky, pasty clay that rapidly clogs all rock fractures and crevices.



(*After H. J. Steiny, California State Mining Bureau, Department of Oil and Gas.*)
FIG. 180.—Arrangement of equipment for mudding under pressure with circulating head.

In cases where oil and gas sands have been mudded off behind the water string at some distance above the cement plug, mud is sometimes pumped down between the conductor pipe and the water string, until the formation does not absorb further fluid. The space behind the water string is thus left filled with heavy mud, which effectively prevents intercommunication of fluids between the strata penetrated. Wells so mudded have maintained the same fluid level behind the water string for years, proving conclusively the effectiveness of the process.

Protection of Oil Sands against Water Incursion in Abandoning Wells. After production declines to a point where operation is no longer profit-

able, precautions should be taken against water incursion before the well is abandoned. It is customary to salvage as much of the casing as can be recovered, and since withdrawal of the casings will admit water to the oil sands, the wells must be plugged. Even though the water string is left intact, corrosion will eventually result in failure of the casing to retain the fluids of the overlying formations.

The well is preferably plugged with cement to a point above the cap rock immediately overlying the oil zone, the cement being mixed and placed in the well by either of the methods described in the foregoing pages. Dump bailers are often used for this purpose, though the cement is more expeditiously inserted by pumping through tubing.

There is good reason to believe that the oil measures may be adequately protected in abandonment proceedings by mudding under pressure, a process that should be somewhat less expensive than plugging with cement. A hole left full of thick mud, after circulating until absorption of fluid by the wall rocks practically ceases, offers little opportunity for intermingling of fluids from different horizons; and if there is sufficient clay in the fluid to fill the hole, after settling, to a point well above the top of the oil sand, the clay plug so formed should offer ample protection against water incursion from above. However, it is not always easy to mud an exhausted oil sand so that it does not continue to absorb fluid; and unless the wall rocks may be made practically impervious, the mudding process cannot be relied upon for permanent protection.

TESTING EFFICACY OF WATER SHUT-OFFS

On completion of a cementing job or other work designed to exclude water from a well, a test should be made to determine whether or not it has been successful. If cement has been used, such a test should not be made until it has had time to set and harden properly. Any cement left within the casing is first drilled out, and a hole drilled for a depth of 10 or 20 ft. ahead of the shoe of the water string. The fluid is then bailed from within the casing until the level is sufficiently below that at which the fluid stands outside the casing, to allow water to enter if it is able to do so. After bailing, the fluid level within the casing is carefully measured and recorded. The well is allowed to stand 12 hr. or more, when a second measurement of the fluid level within the casing is made. If the level has not changed materially, the shut-off is regarded as successful. Draining of films of water down the inner walls of the casing after bailing may raise the fluid level slightly. Even though a slight leakage of water under the shoe is apparent, it may be considered too slight to justify further repair work.

Occasionally gas entering the casing from the formation below the shoe of the water string will cause the fluid within to rise, perhaps leading to

the erroneous conclusion that water has not been effectively excluded. In some fields, such as the Ventura field of California, owing to the presence of large quantities of gas in the formation, it is considered unsafe to lower the fluid level inside the casing sufficiently to secure a fair test of water shut-off by the usual method. In this case the fluid level within the casing is lowered only about 500 to 700 ft. below the surface and samples are then taken of the fluid in the bottom of the well. The overlying formations are highly saline and any increase in the percentage of salt in the well fluid is considered evidence of an unsuccessful shut-off.

Measurement of fluid level within a casing may be made with the aid of a heavy plumb bob and a steel measuring line, on a suitable reel mounted above the well mouth on the derrick floor (see page 382). If cable drilling tools are available, it is customary to make fluid-level measurements with the sand line and bailer. The bailer is run into the well until it is submerged or partially submerged below the water level. A mark is then made on the sand-line level with the derrick floor, and, as the bailer is withdrawn from the well, the length of line is measured below this mark to the point where first moisture on the line or bailer shows the water level to have been. The process of measuring the sand line is readily accomplished by determining the length of line from the derrick floor up over the crown block and down to the level of the sand-reel flanges. This unit of measurement is applied by tying a strand of manila fiber to the line at the level of the derrick floor and raising the bailer until this strand reaches the sand-reel flange. The strand is then removed and another placed on the sand-line level with the derrick floor, and the process is repeated until the wet portion of the cable or bailer emerges. The number of strands untied from the line at the sand reel, plus one, multiplied by the unit length over the crown, plus the fractional interval from the last strand down to the derrick floor (as measured with the gage stick or tape) is the depth to water level.

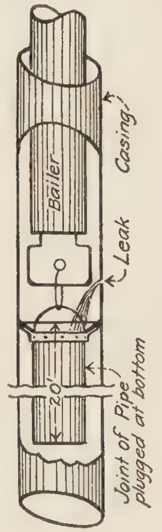
REPAIRING UNSUCCESSFUL SHUT-OFFS

If tests made as outlined above indicate that the effort to exclude water has not been successful, further tests must be made to determine the nature of the difficulty. Perhaps, owing to one or another of the physical and chemical variables already discussed, the cement has not set; or, if it has set, open channels through it may have been left. Perhaps the cement plug is structurally misplaced and the water is coming from formations below the plug. Occasionally, casing leaks above the shut-off will admit large quantities of water.

Locating the Source of Water Entering a Well.—In locating the source of water entering a well, tests should first be made to determine whether or not the casing leaks. Testing for casing leaks may be conveniently conducted with a casing tester (see Fig. 181), which is alternately lowered to successively greater depths and hoisted to the

surface until it brings up water. The casing may have become worn through by abrasive action of the drilling cable or drill pipe; or it may have split at a defective weld, or as a result of application of a swage; or the leak may be at a loose collar which is cross-threaded, or which has become unscrewed in the well.

If the leak is not in the casing, a test should next be made to determine whether water is finding its way down through or around the cement plug and under the casing shoe, or whether it comes from some lower source. For this purpose, a "bridge" should be placed a few feet below the shoe, sealing off the hole that has been drilled below. This plug is built up from bottom in successive stages with the aid of wooden or lead plugs and cement. If further tests indicate that water has been excluded by this process, it may be concluded that the shut-off has been placed too high and water-bearing formations occur below the casing shoe.



(*After R. E. Collom, California State Mining Bureau, Department of Oil and Gas.*)

Fig. 181.—Illustrating method of using casing tester.

We may locate the source of water in a well below the shoe of a water string by plugging with cement in stages, testing after each stage to determine whether or not water has been excluded. An alternative plan is that of plugging back to the shoe of the water string and then drilling out in stages.

In drilling it is a good plan to obtain and preserve samples of the fluid from each water-bearing horizon penetrated. Chemical analysis may disclose characteristic changes in saline content in the waters from different horizons. Later, if water exclusion operations are unsuccessful, it may be possible to identify the water entering the well and determine the horizon from which it comes by making a chemical analysis and comparing the result with the record of earlier analyses of samples taken during the drilling period.

If samples are not taken during the drilling stage and analyses made, we may still make use of chemical analysis as a means of identifying the source of water by filling the well with fresh-water or mud fluid, then bailing or swabbing out enough fluid to cause water to enter from the formation, sampling at various depths and making chemical analyses in the hope of finding a variation in saline content of the well fluid. An increase in saline content will necessarily be opposite the point at which water enters.

A convenient means of determining the source of water in a well is afforded by the Water Witch, an instrument which indicates differences in the electrical conductivity of fluid at various depths. This is a patented device the use of which is controlled by Oil Fields Service Company, Los Angeles, Calif.[4] The instrument comprises two electrical terminals, supported some distance apart in a metal shell to which the well fluid has access. It is lowered through the well on a double-wire insulated cable while an electric current is caused to flow through the cable circuit and between the two terminals through the well fluid. The resistance to flow, determined largely by that offered by the well fluid between the terminals, is indicated on an ammeter at the surface. The entire equipment is moved about on a motor truck especially equipped with a hoisting drum for reeling the cable into and out of the well. A bank of storage batteries provides a source of direct current. Variations in resistance offered by the well fluid at different depths afford a positive and dependable indication of the point at which water enters from the formation, providing it has a saline content sufficient to cause measurable differences in conductivity. Figures 182 and 183 present characteristic graphs of resistance measurements secured with the Water Witch.

Remedial Measures.—The nature of the remedial measures to be taken, in the event that an attempted shut-off has proved unsuccessful, will depend upon the source of the water and the way in which it finds admission to the inner portion of the casing.

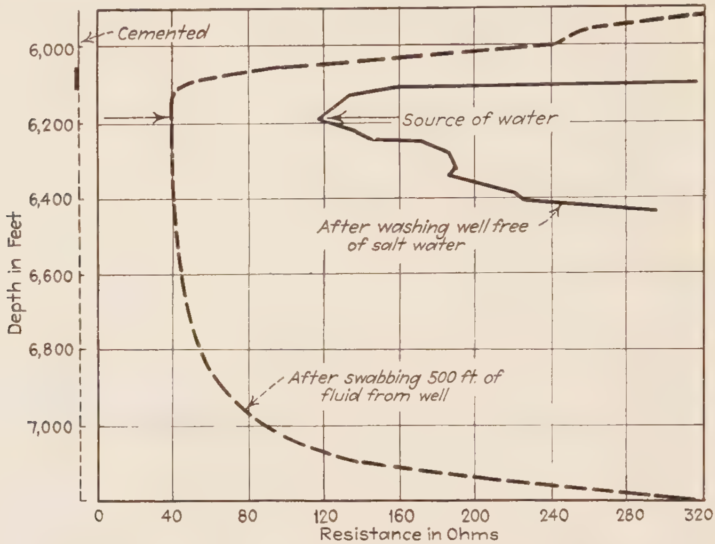


FIG. 182.—Water Witch indication of a high-head top-water leaking under casing shoe.

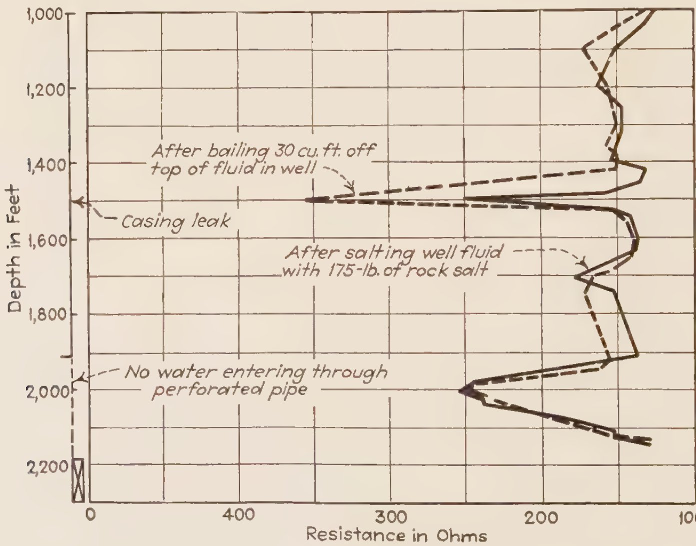


FIG. 183.—Water Witch indication of a casing leak (fresh water outside of casing).

If cement has been used and has failed to set, it will be possible to raise the casing, bail out the cement and repeat the cementing operation after studying the cause of the failure and making such changes in methods or materials as seem desirable. If the cement has set properly but has been ineffective, a more difficult problem is presented. If tests indicate that water is entering under the shoe, it may be possible

to force cement back of the shoe under pressure, using the tubing process; but this procedure will usually not be effective unless it is possible to secure circulation through the defective cement plug. If the cement plug is a short one, it may be possible to part the casing above the cement with the aid of explosives and so shatter the detached casing and cement that it can be drilled up or sidetracked; but often this will not be possible and it will be necessary to "sacrifice" a string of casing by cementing a smaller water string below the first.

If water is entering through a leak in the pipe and not around the shoe, and the hydrostatic head likely to be developed above the leak is not great, drilling may be continued and the well completed in the usual way. The inner string of casing, or "oil string," may then be extended to a point above the leak in the water string and mechanical packers set between the two to exclude water. If this procedure is considered unsafe, owing to the size of the leak and the hydrostatic head likely to be developed above it, a bridge should be placed in the casing immediately below the leak and an effort made to force cement through the hole in the hope of forming an impervious layer of cement on the outside of the pipe. If the hole is small, application of a casing perforator or ripper will form larger holes through which cement will pass. If it is suspected that water is entering the well through a loose coupling, it may be possible to remedy the difficulty by giving the casing a few turns at the surface.

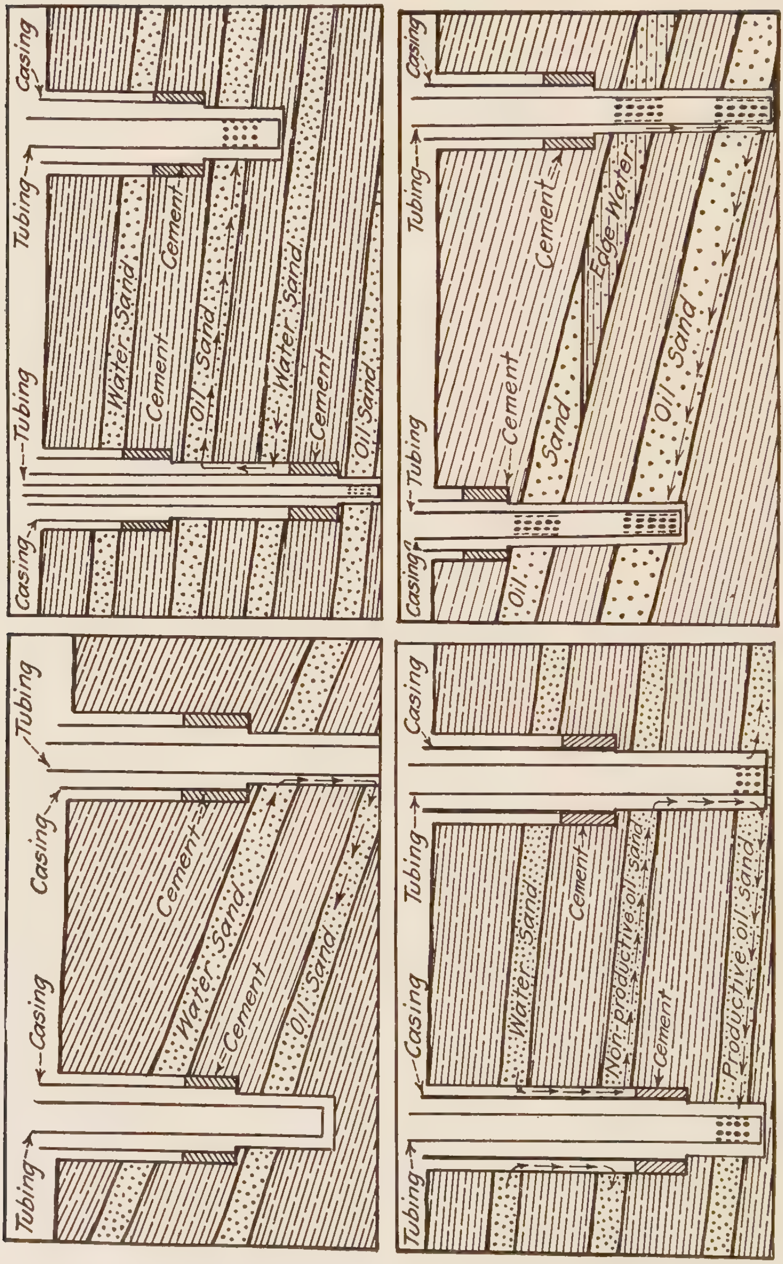
Some of the most difficult and uncertain cases are encountered in attempting to shut off water which occurs as intermediate water in a zone of productive oil sands or in the base of a thick productive stratum. Here every precaution must be taken to avoid cementing the productive sands. In some cases, also, top waters are separated from the oil zone by only a few feet of impervious material, and very accurate knowledge of the depths and thicknesses of strata is necessary to land the water string and cement it before it enters the oil zone, and still be assured of placing the plug so that it is continuous throughout the water zone.

When drilling in territory in which the stratigraphy is not definitely known in advance, a well will sometimes be drilled below the logical point for a water shut-off before the necessity for it becomes apparent. In such a case, it is necessary to withdraw the casing until the shoe is at the desired level and then plug or bridge over the lower portion of the hole before introducing the cement.

Importance of Stratigraphically Uniform Shut-Offs in Contiguous Wells.—A study of the possibility of water migration from well to well through porous strata will indicate the importance of stratigraphic uniformity in the placing of water shut-offs. Figure 184 illustrates some of the cases arising from failure on the part of the neighboring operators to recognize the necessity for cooperation in deciding upon the selection of a particular stratum in which to make all water shut-offs. Correlations for this purpose, and determination of landing depths for water strings, constitute an important aspect of systematic water exclusion. Such work should be entrusted to some state or semipublic technical commission rather than left to the whim of individual operators. In California the depth at which the water shut-off is to be made in every well is specified by the State Oil and Gas Supervisor or his deputy.

Locating the Source of Water in a Group of Flooded Wells

In many cases it is a difficult matter to determine the source of water which is finding its way into an oil sand. Occasionally, large quantities



(*In part after R. P. McLaughlin, California State Mining Bureau, Department of Oil and Gas.*)

Fig. 184.—Illustrating manner in which water may migrate from one well to another.

of water will be admitted to the productive sands through a single well, until neighboring wells are influenced, perhaps cutting off all production from an entire group within a few months' time. It is evident that such a condition will occasion large losses, and there will be ample justification for the expenditure of a considerable sum in repair work if by so doing the condition can be remedied. When such a situation presents itself, it usually requires a careful study of all of the available information to determine which well is at fault and, when this is done, to locate the source of the water.

In determining which well of a group is admitting water to the productive strata, recourse may be had to several methods of procedure. A close stratigraphical correlation of water shut-offs with the aid of a peg model may disclose the fact that in one well the cement plug provided to exclude top water has been placed too high, or that the well has been drilled into bottom water. A study of the drilling history of each well may disclose facts which will aid in reaching a conclusion. Perhaps a water string has corroded to such a degree that water has found admission, or it may be that a cement plug has disintegrated as a result of the use of unsound cement or by contact with reactive ground waters. Again, if the wells are producing from several different sands comprising a zone, an edge-water condition developing in one sand may occasion apparent flooding of others. For example, in the sketch reproduced in the lower right of Fig. 184, edge water in the upper sand in the well at the right may eventually flood the lower sand in the left-hand well. A carefully kept series of production records giving the amounts of water and oil produced by each well of a group will be of great assistance in determining which well or wells were first influenced and which produce the largest percentage of water. Attention can then be focused on these as likely offenders. A study of fluid levels in a group of wells will often disclose the faulty well as the one having the highest fluid level.

Use of Dyes and Dissolved Salts as Flow Detectors.—It is occasionally possible to prove that water is flowing from one well to another by inserting an easily detected dye or chemical substance in the well into which the water is flowing, and observing its later appearance in the water pumped from surrounding wells. This is a test that may be applied after attention has been focused on the offending well of a group by a close study of the evidence.

The dyes commonly used are fluorescein, eosine, magenta and other fluorescent organic dyes. Fluorescein, which has a distinctive yellowish green color by reflected light, is apparently best adapted to the purpose.[3] It can be detected in water by the naked eye when present to the extent of 1 part in 40,000,000, and, with the aid of the fluoroscope, 1 part in 2,000,000,000 can be detected. Furthermore, it is not appreciably adsorbed by clays and may travel for a considerable distance under ground without change in its physical properties. Eosine is a brick-red dye that is not quite so easily detected in minute quantities as fluorescein. The dye should be dissolved in a bucket of water and either poured into the well or lowered in a glass container on the bailer or a cable drilling bit. On reaching bottom, a blow with the dart of the bailer or

with the bit breaks the container and liberates the dye. The amount of dye necessary will depend upon the quantity of water the wells are producing, and upon a consideration of the opportunity for diffusion and the concentration necessary to produce an easily detected color. Usually a great excess is used—from 15 to 100 lb.—as a precaution against loss through adsorption, diffusion and dissipation in other ways. Instances are on record where dyes used in this way have passed through the earth over distances as great as 900 ft. in about 3 hr. time.[1]

A similar use of various soluble salts, such as lithium, sodium, calcium or ammonium chlorides or nitrates, has been suggested, identification of the foreign substance in the ground water being effected by chemical analysis.

It should be pointed out that the use of dyes and other flow detectors in tracing the movement of underground water is more or less unsatisfactory since the results are too often negative. If the detector can be shown to have moved from one well to another, it will have served its purpose; but if the result is negative and the detector does not appear, there is always the uncertainty of whether or not some unforeseen factor has prevented it from having proper access to the water channels, or whether it has been subjected to conditions which may have changed its physical or chemical characteristics.

Success in Water Exclusion Requires Close Engineering Supervision. Some of the most intricate and difficult problems in oil field development are encountered in the exclusion of water from wells, and every phase of the work must be under engineering control. Selection of the landing point of a water string should be based upon accurate information that can best be secured by coring, followed by engineering inspection of the cores with due regard to thickness, permeability and hardness of the stratum upon which dependence is placed for security against passage of water around the cement plug through the formation. The well must be properly conditioned and the conditions within the well must be accurately interpreted. The physical and chemical properties of the cement used must be determined. The space to be filled by the cement plug, the necessary volume of cement and the amount of accelerator or other reagent to use must be carefully computed. The proper proportions of cement and water in the mix and the volumes of water, cement slurry and mud fluid used in pumping down the mixture must be accurately measured. The procedure followed in mixing and placing the cement must be expeditious and must be so planned as to proceed with minimum likelihood of interruption or accident. Tests to determine the success or failure of the work must be conscientiously performed. If failure has resulted, accurate diagnosis of the reason therefor, estimation of conditions within the well and planning and conduct of the necessary remedial measures require engineering ability of a high order. All of this work is exacting and is properly placed under the immediate direction of a trained engineer, adequately informed on cement technology and familiar with the peculiar nature of the problems presented and the difficulties to be overcome.

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CHAPTER XI

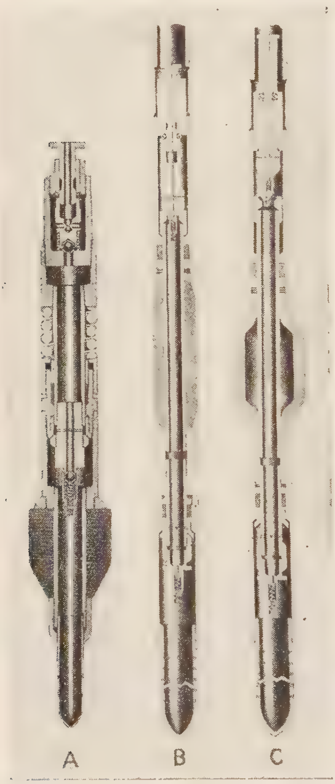
FINISHING THE WELL

On encountering an oil or gas stratum which gives evidence of being commercially productive, the driller proceeds carefully and cautiously. Perhaps the stratum is under high pressure, and unless precautions are taken there is danger of a blow-out which may be accompanied by an uncontrollable flow of oil and gas. Reduction of the specific gravity of the mud-laden fluid by contamination with occluded oil and gas will sometimes be responsible for a blow-out in rotary drilling. Such an event usually results in great loss of oil and gas and often seriously damages the well and its equipment. If the producing stratum is an unconsolidated sand, the well may "drill itself in" as soon as the cap rock is penetrated, large quantities of sand flowing to the surface with the oil and gas and forming a cavity in the oil sand about the well.

If the oil sand is under low pressure, there may be very little evidence of the presence of oil during the ordinary processes of drilling. A high fluid level within the well may prevent any oil or gas from escaping from the sand. If the rotary method of drilling is employed, the sand faces soon become rapidly mudded so that their true character is obscured. The circulating fluid may so thoroughly wash the cuttings from the drill that little evidence of the presence of oil remains. To the trained eye of the driller, however, there will usually be evidence that at least leads him to suspect the presence of oil. Perhaps a little oil sand clinging to the drilling bit or the bailer, or a few globules of oil or gas froth on the mud ditch, will tell the story. If there is evidence of oil and the rotary equipment is in use, the clay content of the circulating fluid should be at once reduced by adding water to the fluid in the mud pit. A core of the material in the bottom, taken with a suitable core barrel, will give positive evidence. If the cable tools are used, the bailer will usually bring up samples of the material in the bottom that have not been greatly disturbed. A chloroform test will be decisive if there is any doubt of the presence of oil.

Special tools called "formation testers" are available for securing a sample of the fluid within a stratum in the bottom of the well when drilling with rotary tools, without removing the mud fluid from the well. One type of tool designed for this purpose is illustrated in Fig. 185*A*. In preparation for its use, a "rat hole," somewhat smaller in diameter than that of the well, is drilled into the formation in the bottom. The tool is then lowered on the end of the drill pipe and seated with the conical packer in

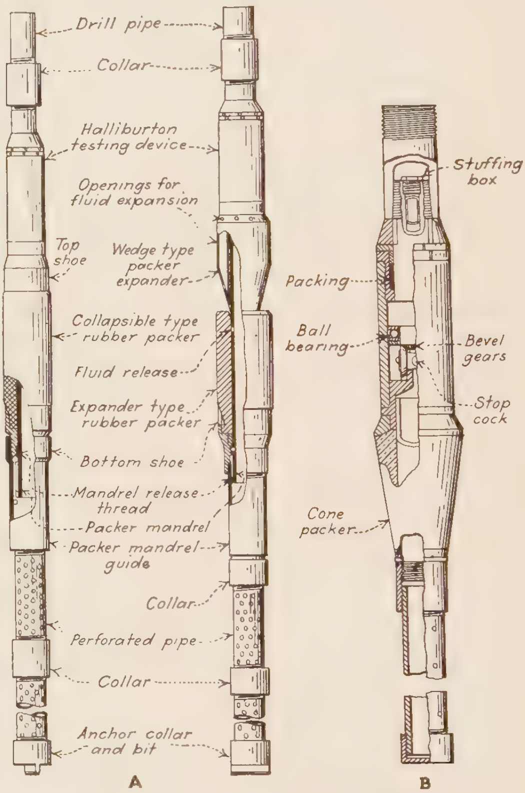
the upper end of the rat hole. The weight of the drill pipe compresses the heavy spring, thus opening the lower of the two valves. The upper valve is then tripped by dropping a "go-devil" in the form of a short section of small-diameter pipe through the drill stem, when an uncontaminated sample of the fluid below the packer may flow into the chamber



(*Courtesy of Johnston Formation Tester Co.*)

FIG. 185.—Types of Johnston formation testers.

A, rat-hole type; *B*, full-hole type, rubber packer extended; *C*, full-hole type, packer expanded.



(*Courtesy of Halliburton Oil-Well Cementing Co.*)

FIG. 186.—Types of Halliburton formation testers. *A*, open-hole types; *B*, rat-hole type.

between the valves, and thence into the drill pipe above. Another type of formation tester, illustrated in Fig. 186*B*, is also lowered on the drill pipe into a rat hole drilled into the bottom formation. After the packer is set, the lower end of the tool is opened and the fluid below admitted to the drill pipe by rotating it a few turns to the right. On drawing out, the tool automatically closes and traps an uncontaminated sample. Other somewhat less dependable types of formation testers are designed to operate in a very similar way in open hole (see Figs. 185*B* and 186*A*).

While we may depend upon such indications and tests for qualitative evidence, it is often difficult to form any estimate of the probable productivity of the well without making an actual production test. The well is "bailed down" to remove the hydrostatic head on the oil stratum and allow the oil and gas to escape from the sand. This is done cautiously in order to avoid a sudden flow which might be difficult to control. As the hydrostatic head is gradually reduced by continued bailing, oil will begin to enter as soon as the balance of pressure is in its favor and will float to the top of the fluid in the well, increasing in quantity as the head is reduced. If the productive sand is unconsolidated, it may tend to "heave" or flow into the well with the oil, occasionally filling the hole for hundreds of feet above bottom and necessitating prolonged bailing or even redrilling. If there seems to be danger of this, care should be taken not to bail the well down too rapidly or too far, and the bailer should be lowered to bottom for its load in order to observe the tendency of the sand to enter.

In the case of reservoir rocks of limestone or "tight" sands or shales, it is usually necessary to make an actual pumping test for a few days before the full productivity may be realized. In hard, close-grained rocks, such as the limestones, it is also customary to "shoot" the wells in the hope of fracturing the oil stratum so that oil may freely enter. Rush of gas from the well as a result of a shot of nitroglycerin or dynamite often causes a flow of oil which sometimes lasts for several days or weeks, though the well may have given little evidence of the presence of oil prior to shooting.

It will be noted that the manner in which oil makes its presence known as the drill enters the oil stratum varies markedly, depending upon the nature of the reservoir rock and the pressure under which it is stored. The method of drilling employed also has its influence in determining in some measure the hydrostatic head resisting entrance of the oil. In high-pressure territory there will be no uncertainty, and flowing wells or gushers, in which the oil is thrown from the well mouth high into the air, occasionally offer new problems in control of exceedingly destructive forces. In the case of low-pressure strata or close-grained rocks, on the other hand, the skill and ingenuity of the driller may be taxed to the utmost to establish conditions within the well which will cause it to yield oil in commercial amounts.

Setting the Oil String or Liner.—Drilling should be continued until the oil stratum is penetrated, and, unless bottom water is encountered immediately below, the hole should be drilled for an additional 10 or 20 ft. This serves as a sump for the accumulation of sediment or cavings from the walls, or for sand which may enter with the oil, and also as a reservoir in which oil may accumulate. It is important that sand enter-

ing with the oil should not accumulate within the well opposite the producing strata since it reduces the rate of production.

If the walls are firm and do not tend to cave, the well may be completed without casing of any sort opposite the productive horizon. This practice is characteristic in most of the fields of the eastern United States. The last string of casing or the "oil string," so named because it is the only one in contact with the oil, is in this case carried to a point immediately above the oil stratum and set on a firm shoulder of rock in such a way as to exclude water and cavings from above.

If the productive formation is a loosely cemented sand or sandstone, as is generally the case in the fields of California, Louisiana and southern Texas, it is necessary to carry the oil string through the oil sand to the bottom of the well; and in order that the oil may gain admittance to the pumping device which is placed within the casing, the pipe is perforated opposite the oil sand with numerous round holes or slots. These openings are frequently equipped with screens of various types which allow the oil to pass but exclude the sand which tends to flow in with the oil. The lower end of the oil string rests on bottom and should be securely plugged to prevent water or heaving sand from entering from below.

Perforating the Oil String

The oil string may be either perforated in the shop by drilling holes or cutting slots in it before it is placed in the well, or it may be perforated in the well with the aid of a casing perforator.[18] Shop-perforated pipe is preferable since the holes are more uniformly spaced, the openings are clean cut and the casing is left in better condition than when it is perforated in the well. Furthermore, the operation of the perforator is always somewhat uncertain. However, it is sometimes unsafe, because of tendency of the walls to cave, to remove a string of casing from the well to insert shop-perforated pipe. In such a case, reliance must be placed on the successful operation of a casing perforator.

Perforating casing in the well is accomplished with the aid of one or another of the various forms of casing perforators of which there are two principal types: (1) the single-knife perforator similar in many respects to a casing ripper, and (2) the wheel-knife perforator equipped with one, or sometimes two, star-shaped wheels the points of which, when brought to bear against the inside of the pipe, cut slots in it.

The single-knife perforator consists of a substantial frame or body *a*, in which a steel knife *b*, pivoted at one end, is mounted (see Figs. 187 and 188). The knife is actuated by a mandrel *c*, which is free to move up and down in a slot, cut through the body of the tool below the knife. A spring *d* presses firmly against the inside of the pipe. The spring is free to move up and down on the mandrel, except when engaged by the latch *e*. The tool is lowered on tubing to the depth at which it is desired to perforate the casing and then pulled up a short distance. The spring *d*, pressed

tightly against the casing, will drag so that the mandrel c will be pulled up through the spring until the latch e is engaged. The tubing is then again lowered, the spring remains stationary because of its pressure against the pipe, continued descent of the tubing causing the knife to force its way through the pipe. The tool is then raised a short distance, allowing the knife to drop back into position to cut another perforation.

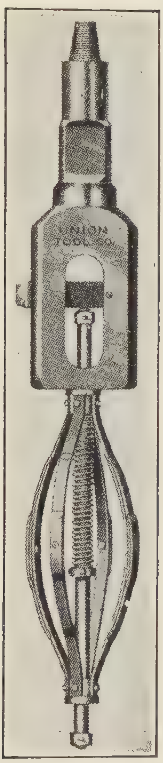
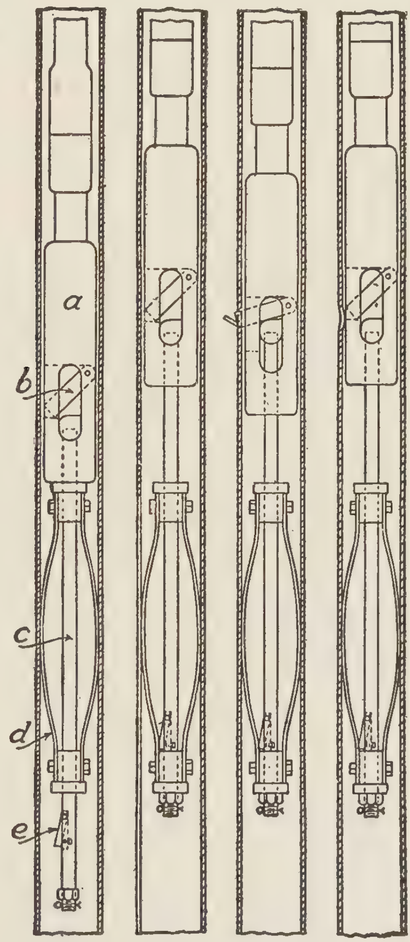


FIG. 187.—Casing perforator.

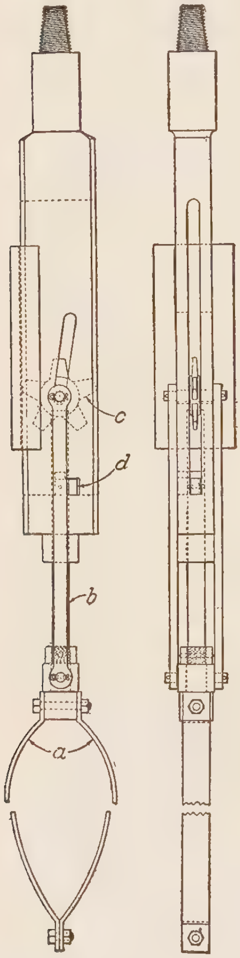


(*After P. M. Paine and E. W. Wagy.*)

FIG. 188.—Illustrating action of single-knife perforator. *a*, body; *b*, knife; *c*, mandrel; *d*, spring; *e*, lug.

By carefully measuring the movement of the tubing on which the perforator is suspended, the holes punched can be uniformly spaced at any desired distance. By rotating the tubing through 90 or 180 deg., four or two rows of perforations can be cut around the circumference of the pipe. The shape of the knife controls the form and size of the perforation. The tubing is sometimes filled with water in very shallow wells to add weight, or a string of fishing tools may be rigged and the perforator driven down with the jars.[18]

Wheel-knife Perforators.—A number of well-known and commonly used casing perforators are in this group, notably, the Hardison, Star, Brinkman, Mack and Basch perforators. The first three mentioned are equipped with one wheel knife, cutting one row of perforations at a time, while the latter two are equipped with two wheels and cut two rows 180 deg. apart with each application. A four-knife perforator is also on the market, which punches four rows of holes 90 deg. apart, but it is said to be unduly complicated in its mechanism and to lack rigidity.



(*After E. W. Wagy, U. S. Bur. Mines, Tech. Paper* 247.)

FIG. 189.—"Star" perforator.

a, spring; *b*, mandrel; *c*, knife; *d*, lug.

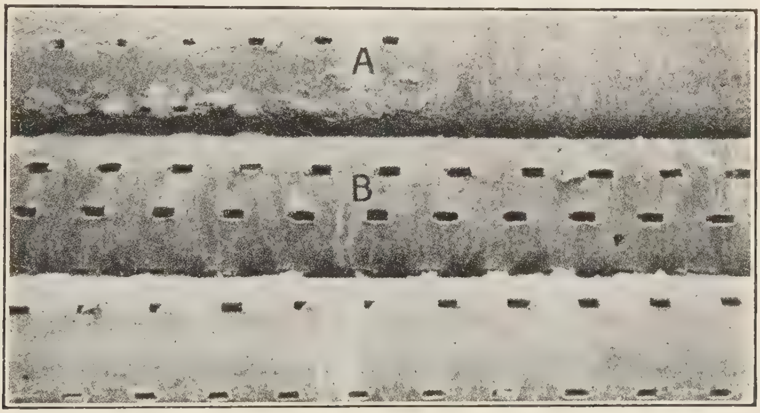
The Star perforator will be briefly described as typical of the group of wheel-knife machines. It is operated on tubing and depends upon a spring *a* and mandrel *b* for setting the knife *c*, which is shaped like a five-pointed star (see Fig. 189). A lug *d* on the mandrel prevents the knife from moving out of its position within the body of the tool while it is being lowered into position, but when the depth is reached at which it is desired to begin perforating, turning the tubing releases the lug from its recess. Further lowering of the tool forces the mandrel upward, pressure of the spring on the end of the mandrel holding the latter stationary as the tool is lowered. As the body of the tool is lowered over the mandrel, the wheel knife mounted on the upper end of the mandrel is forced up the inclined slot until the points bear against the pipe. Further downward pressure on the tool causes the knife to revolve, punching a hole as each point of the knife is forced against the pipe. After one vertical row of holes is cut in this way, the tool is raised to its original position, turned through 90 or 180 deg. and again forced downward.[18]

The shape of the cutting points of the wheel knife can be varied to produce any desired form or size of slot (see Fig. 190). The size of the wheel and the number of points on it determine the spacing of slots. Single-knife wheel perforators can be adapted to different sizes of pipe by the use of adjustable backs, such as that indicated in Fig. 189. Double-knife perforators, which cut two rows of perforations at once, must be designed for the particular size of pipe in which they are to be used. Double-knife perforators have a tendency to flatten the casing if used on thin-walled pipe, as a result of the strain exerted on two opposite sides simultaneously.

Casing perforators must be rugged since the duty imposed is very severe, and they should contain as few working parts as possible. In long strings of heavy casing, where the walls to be perforated are thick and there is more or less spring in the pipe and tubing, the perforator must be worked alternately up and down against the pipe for each hole cut. This is accomplished, if the cable-tool equipment is in use, with the aid of a jerk line from the wrist pin, a connection such as is used in spudding operations. Two-way perforators are run below a fishing string on the drilling cable and are driven down with the jars. Manipulation of a casing perforator on a string of tubing is more satisfactory than on a drilling cable, since the operator is better able to control the position of the holes punched. A single-knife machine cannot be satisfactorily operated on a drilling cable.

The perforator should be tested in a joint of casing before the tool is lowered into the well. Even when the machine is known to be in good condition, however, there will be some uncertainty in its action due to slight differences in diameter of the pipe, or thickness and hardness of the metal walls. All of the perforating should be done if possible without removing the perforator from the well; otherwise there is danger, during a second application, of the second series of perforations encountering the first, causing local fracturing or tearing of the metal, and greatly weakening the pipe (see Fig. 191). Care must be taken not to cut too near a coupling. If a hole is punched through a coupling, there is danger of the pipe parting or collapsing. An accurate casing record is essential in determining at what depths to perforate.

While most manufacturers of casing perforators contend that their machines are universally positive and reliable in action, some of the best types occasionally fail to accomplish their intended purpose. In some instances, casings drawn from wells have been found to have been merely dented by the perforating machine or only partially perforated. Operators have thus been led to believe that their wells were



(*After E. W. Wagy, U. S. Bur. Mines, Tech. Paper* 247.)

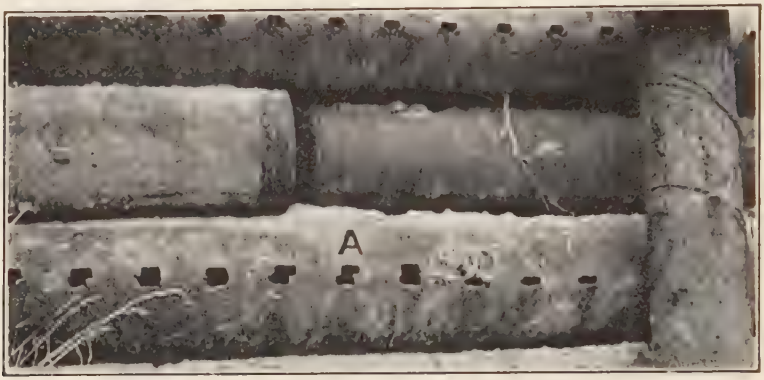
Fig. 190.—Pipe perforated in the well with Star type of perforator. *A*, imperfect and *B*, properly cut perforations.

small producers or barren, whereas if the casing had been properly perforated they would have been good producers. Perforators are also occasionally responsible for ripping or splitting of the casing, a series of misplaced perforations sometimes so weakening the pipe that it collapses or parts in the well.

A more positive and dependable method of perforating casing in the well is afforded by the Lane-Wells gun perforator. This device shoots sharp-pointed steel bullets through the casing from the inside, with the aid of high explosives. A series of loaded "guns" mounted one above another, in a massive steel frame, is lowered through the casing on a conductor-cable to the point where the perforations are to be formed. The several electric conductors contained within the core of this cable are connected with a source of electric current at the surface in such a way that the different charges may be fired one at a time. The explosive is fired by a metallic filament which is heated to incandescence by passage of the current. The guns are so designed that they are water-tight under high fluid pressures. The tool containing the guns, together with the special cable on which it is lowered, is carried to the well on a service truck especially equipped with a hoisting drum and electrical equipment for firing the charges and testing out the circuits. This method of forming perforations in casing is rapid, and the holes formed in the casing are clean-cut, with but little

distortion of the surrounding metal. Bullets have been fired by this device, through three concentric strings of heavy casing with cement between.

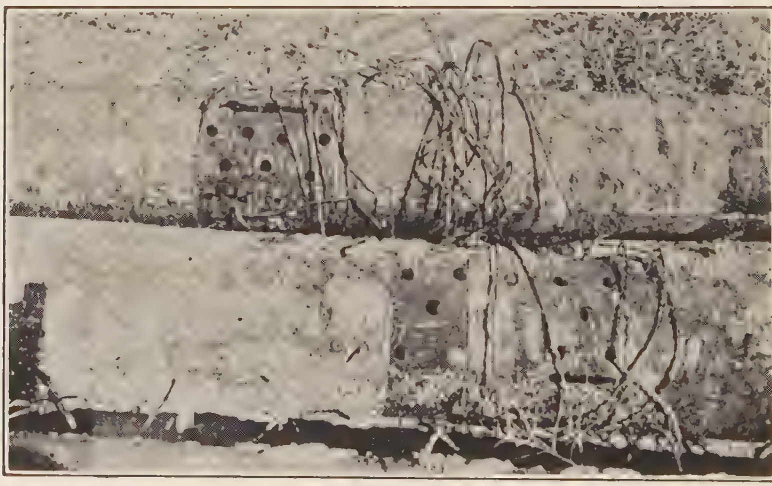
Shop-perforated pipe may be prepared in the shop with the aid of the drill press, boring round holes which may range from $\frac{3}{8}$ to $\frac{3}{4}$ in.



(*After E. W. Wagy, U. S. Bur. Mines, Tech. Paper* 247.)

FIG. 191.—Casing damaged by double application of perforator (see pipe marked *A*).

in diameter, depending upon the nature of the oil sand and the type of screen to be used. The holes are bored in longitudinal rows, 30, 45, or 60 deg. apart on the circumference of the pipe (that is, 6, 8 or 12 rows), with



(*After E. W. Wagy, U. S. Bur. Mines, Tech. Paper* 247.)

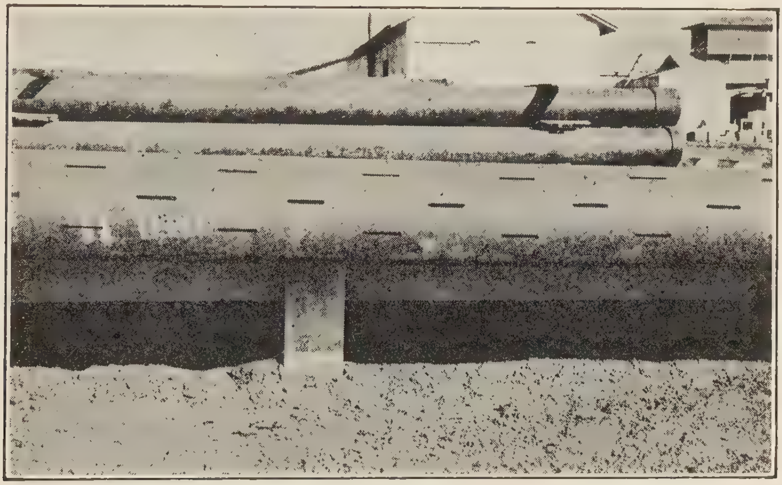
FIG. 192.—Shop-perforated, screen-wrapped pipe, showing clogging of screens after removal from well.

the holes 4 or 6 in. apart and staggered in alternate rows (see Fig. 192). The rows of holes extend over a length of pipe equivalent to the thickness of the oil sand. The number of holes and their spacing will depend upon

the size of the pipe, care being taken to avoid undue weakening of the metal resulting in danger of its parting or collapsing in the well.

Liners or oil strings are sometimes made up of oxyacetylene welded pipe, and inserted joint casing is also occasionally used. The projecting collars of ordinary collared-joint casing are often particularly troublesome in unconsolidated sands containing oil. Nevertheless, this latter type of casing is generally preferred to the inserted joint because of its greater strength. Inserted-joint casing must be perforated in the shop, since it is too weak to withstand the action of a perforating machine in the well.

Some operators prefer a slot-shaped opening to the round holes formed by the twist drill, claiming that the former allows less sand to



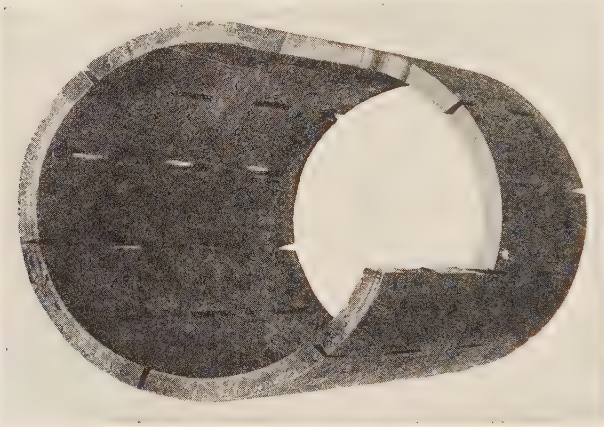
(After E. W. Wagy, U. S. Bur. Mines, Tech. Paper 247.)
FIG. 193.—Slotted pipe.

pass than the latter. Slots may be cut with a planer or shaper or with the oxyacetylene torch. Drops of molten metal forming on the inside of the pipe as a result of the use of the torch are sometimes detrimental to swabbing and other like operations. Narrow slots are usually preferred, but it is scarcely practicable to cut them less than ⅛ in. wide and they are occasionally as wide as ½ in. The length of the slots is usually 2 or 3 in., and they are aligned in rows with the longer dimensions parallel with the axis of the pipe (see Fig. 193). Kobe screen pipe, a popular slotted pipe of this type, is illustrated in Fig. 194. Kobe slotted pipe is manufactured by precision methods involving the simultaneous use of several oxyacetylene torches controlled by mechanisms involving many patented features. The Layne and Bowler shutter pipe and the Emsco screen pipe are varieties of slotted pipe in which the slots are punched or cut with special tools in the shop. The slots are in this case

horizontal. Punching slots in this way causes considerable bulging of the pipe, but the manufacturers claim that the shutter opening, which is inclined upward, is more effective in excluding running sands.

Screens used on perforated pipe are of two general types: (1) a variety made by wrapping closely spaced coils of wire about the pipe over the perforations and (2) the so-called "button screen," in which the screen is cast in a small metal disk which is either pressed and swaged or screwed into a circular perforation. The button type represents a more recent development, and in the California fields has largely displaced the wire-wrapped type of screen.[18]

In the construction of the wire-wrapped type of screen the perforated pipe is placed in a lathe and the wire wrapped on as the pipe revolves.



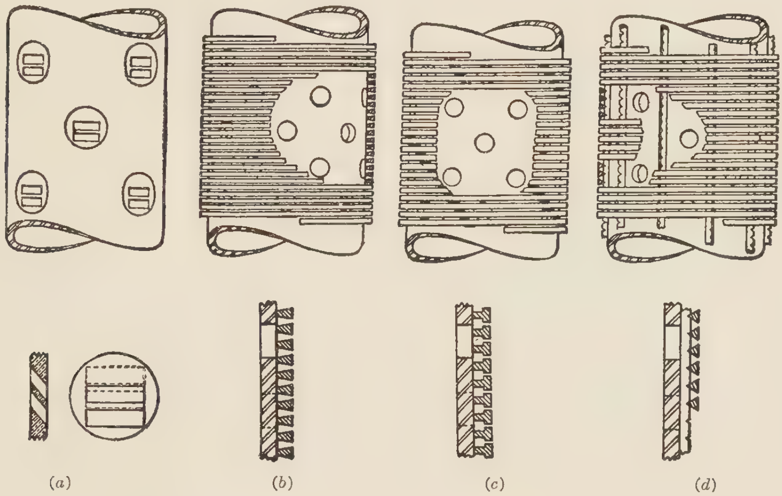
(Courtesy of Kobe, Inc.)

FIG. 194.—Kobe slotted pipe.

The size of wire to select and the spacing of coils depend upon the size of sand particles to be excluded and the gravity of the oil. Round wire was formerly used, but, inasmuch as coils of round wire form wedge-shaped spaces which are readily clogged by accumulated sand, efforts have been made to design screens of angular wires, so placed that a smooth exterior surface is presented with the smallest screen opening on the outer surface. This insures any sand grain that can penetrate the outer opening a free passage through the screen and prevents clogging. Patented screens using wire of angular cross section are illustrated in Fig. 195.

Two well-known types of button screen are widely used in the California fields: the McEvoy screen and the Layne and Bowler screen. The McEvoy button is screened with four thin strips of flat-surfaced metal, forming slots which parallel the axis of the pipe (see Fig. 196). The disks, which are of brass, are inserted in the pipe perforations under

a pressure of 1,000 lb. per square inch and are held in place by swaging the outer edge of each hole against a shoulder on the disk. The manu-



(*After E. W. Wagy, U. S. Bur. Mines, Tech. Paper* 247.)

Fig. 195.—Types of screen pipe.

a, Layne and Bowler button type with shutter openings; *b*, Layne and Bowler keystone wire-wrapped screen; *c*, Getty screen; *d*, Stancliff screen.

facturers claim that the vertical openings, which are flush with the outer surface of the pipe, do not become damaged or clogged by contact with

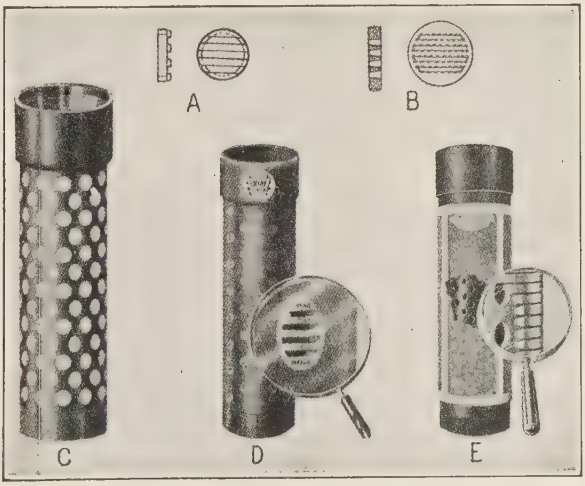


Fig. 196.—Types of screen pipe.

A and *C*, McEvoy wireless well strainer; *B* and *D*, Layne and Bowler, "Skrutite" button screen; *E*, Layne and Bowler wire-wound screen.

the walls of the well while the pipe is being lowered into position. The Layne and Bowler screen is equipped with brass disks about 1½ in. in

diameter, which are screwed into holes drilled and tapped in the casing at intervals of about 6 in. The disks are of the same thickness as the pipe and are flush with the inner and outer surfaces when screwed into position. Two forms of screen openings are available in the Layne and Bowler button: the keystone form (similar to that illustrated in Fig. 196) and a "shutter" slot inclined upward. The slots are in this case horizontal (see Fig. 195).

There have been considerable discussion and experimentation in attempting to determine the best size and form of screen opening. The shutter form is apparently correct in principle if the sand tends to enter simply by caving or falling about the pipe. The angle of repose of the sand and the thickness of the metal forming the slotted openings would determine the effectiveness of ordinary forms if the sand rolls through the openings by gravity. It seems probable, however, that in most cases the sand grains are actually suspended in the oil, perhaps under the influence of gas and hydrostatic pressure. If such is the case, the sand grains would flow with the oil, quite independently of its natural angle of repose, and the form of the opening becomes of little or no importance. The size of screen opening must be proportioned to the average size of the sand grains which are to be excluded. Experimental tests have indicated that a screen opening may have a maximum width about 2½ times the diameter of the sand particle that it is intended to exclude. The sand grains will bridge on the screen if this ratio of screen opening to size of sand particle is not exceeded. If no water is present, the oil-well pump is able to handle a considerable amount of sand without abnormal wear or loss of efficiency, and usually no effort is made to exclude the very fine sands which enter through any kind of screen that will admit a viscous oil. The screen openings should not be so small as entirely to exclude the finer sands, otherwise they will clog about the screen openings and retard the flow of oil into the well. On the contrary, they should be of such size that application of a swab will draw much of the accumulated loose material into the casing so that it can be bailed out and the perforations and screens thus cleared. No rules can be laid down for the selection of a type and size of screen that will meet all conditions. Usually in each field or locality the different available screens must be tried under competitive conditions, and the one selected which gives the best results.

It is important that the screens be made of a material resistant to corrosion by acid or alkaline waters, with which they are often in contact. Brass and galvanized iron are the metals commonly used. In addition to resistance against corrosion the material selected should resist the cutting or scouring action of fine sand, which is sometimes carried through the perforations under high gas and oil pressures. In high-pressure flowing wells, it is advisable to protect the well equipment by maintaining

some back pressure by restricting the outlet, thus holding back the sand and minimizing its scouring action.

The operator must decide for himself whether or not screens are necessary or desirable. In many cases perforated pipe without screens will exclude sand sufficiently well and will offer less resistance to the passage of oil. In some fields it is necessary to allow sand to enter with the oil to maintain the maximum production. In other cases, however, screens will be desirable in order to prevent sand from entering, with consequent increased expense due to the necessity of lifting it to the surface, wear on the pump parts, and necessity of separating it from the oil after reaching the surface. Furthermore, removal of large quantities of sand from about the well causes caving of overlying strata, which may collapse or bend the pipe or which may permit water to enter the oil sand from an overlying water zone.

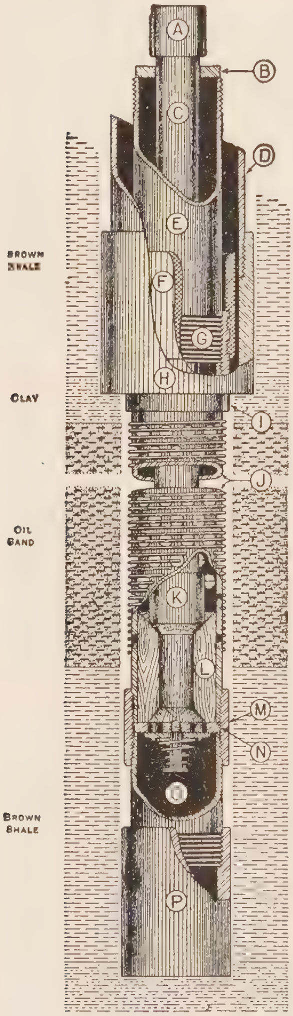
Methods of Setting Screen Pipe.—Bearing in mind the purpose of screen pipe and the weakening effect suffered by the metal as a result of the boring, cutting or punching of numerous holes, it is apparent that the liner must be so handled in the well as to avoid placing undue strain upon it, or great external friction which might displace the wire screening. Also, the screen openings must be left free from mud, sand or other material which might prevent the passage of oil through them. It is advisable completely to wash all mud from the lower portion of the well before attempting to set screened pipe.

If the wall rocks are firm and free from mud, it may be possible to withdraw the oil string, place the proper amount of screen pipe on the lower end and lower it again without danger of the walls caving about the screen pipe as it is introduced. In loosely cemented sands, however, a method must be adopted which will prevent contact of the screen pipe with the walls of the well until it is in place. This is accomplished by inserting the screen pipe as a liner which must be small enough in outside diameter to pass within the oil string which penetrates the oil sand. The screen-pipe liner is plugged at the lower end and is lowered on a column of 2- or 3-in. tubing connected with the screen pipe by a casing adapter and a left-handed swaged nipple. The screen-pipe liner is lowered until it rests on bottom, and the oil string is then raised until its shoe is 10 or 12 ft. below the casing adapter on the liner. The tubing is then turned clockwise, unscrewing the joint at the left-handed swaged nipple, leaving the liner in the well with the adapter on top to serve as a guide for tubing or tools, which must subsequently be lowered into it. The walls usually close about the liner sufficiently, after the oil string is raised, to prevent the screen pipe from turning as the tubing is detached.[18]

Occasionally the oil string will become frozen, so that it is impossible to raise it in this way. It is then necessary to perforate it in the well so

that oil may pass, a liner of screen pipe being subsequently set inside if passage of sand through the perforations becomes serious.

Some operators float the screen pipe into position, simply plugging the lower end of the liner, filling the oil string with water and allowing the screen pipe to sink to bottom under the influence of gravity. The water usually checks the descent of the screen pipe so that it does not settle rapidly enough to cause damage to the pipe or screens. After the liner reaches bottom, the oil string is raised until the perforated pipe is exposed to the oil sand.



(*After* E. W. *Wagy, U. S. Bur. Mines, Tech. Paper* 247.)

FIG. 197.—Wash pipe for setting screen in rotary drilled well, permitting recovery of upper part of oil string.

A, wash-pipe coupling; *B*, steel ring; *C*, wash pipe; *D*, outside casing; *E*, back-off nipple with right and left thread; *F*, lead seal; *G*, left-hand thread; *H*, casing shoe; *I*, lead seal coupling with right and left thread; *J*, screen pipe; *K*, wash-pipe coupling; *L*, wooden wash plug; *M*, coupling; *N*, back-pressure valve; *O*, short nipple; and *P*, casing shoe.

"Drilling in" with Shop-perforated Pipe.—If the position and thickness of the oil-producing stratum are definitely known, as is usually the case in a partially developed field, the proper length of shop-perforated pipe may be placed on the bottom of the oil string just before the oil sand is penetrated. This obviates the necessity of removing the oil string after the hole is completed, an advantage in unconsolidated oil sands, which often tend to cave or heave when the casing is withdrawn or which may freeze about the pipe so that withdrawal is impossible.

Use of Wash Pipe in Setting Screen Pipe.—If mud-laden fluid has been used in the well, as in rotary drilling, or if for any reason mud has settled to the bottom, it will be necessary to wash the mud from the oil sand in order that it may not interfere with production; but in doing so, there is danger of the sand caving into the open hole before the screen pipe can be inserted. In order to avoid this difficulty and still clear the sand pores of mud, it is customary to resort to the use of a wash pipe. This is a tube of smaller diameter than the oil string —usually 2 or 3 in.—which extends through the perforated portion of the string and is packed off at its upper and lower ends, above and below the perforations (see Fig. 197). The wash pipe serves merely to conduct water through the perforated pipe so that it reaches the bottom of the oil string without escaping through the perforations. If rotary equipment is in use, the oil string is often equipped with a rotary shoe or fishtail bit to aid the pipe in cutting its way through the clay which has settled and accumulated in the bottom. The packing device at the lower end of the wash pipe is sometimes provided with a back-pressure valve which prevents heaving sand from forcing its way up inside of the casing.[18]

The oil string, with the screen pipe and wash pipe in proper position in the column, is lowered until the shoe is a few feet off bottom, pumping water through the upper casing and wash pipe to aid in clearing away the mud while the casing is being lowered. When the shoe is but a few feet off bottom, prolonged circulation down through the wash pipe and back to the surface, through the annular space about the pipe, will gradually remove the mud until the sand faces are clear. When the circulating fluid ceases to bring mud to the surface, a string of tubing is lowered into the casing, screwed into the collar on the upper end of the wash pipe, and the latter is slowly withdrawn. As the wash pipe is raised through the perforated pipe, water is continuously circulated through it in order to clear the perforations of accumulated clay and sand. This hydraulic pressure also aids in removing the wash pipe if sand has settled tightly about it. If there is no necessity for clearing the perforations, and hydraulic pressure is not necessary to aid in lifting the wash pipe, it may be removed with the aid of a tubing spear run on a wire cable instead of using tubing as suggested above.

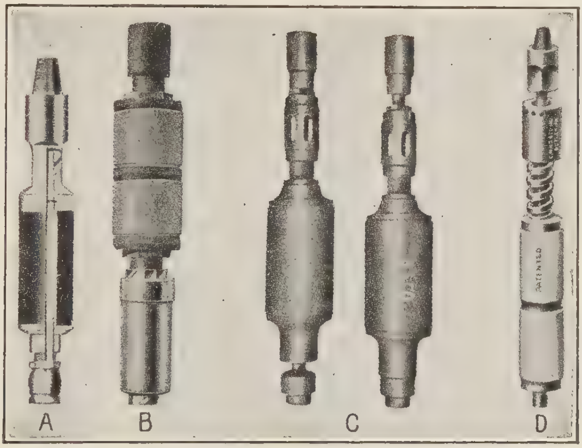


Fig. 198.—Types of swabs.

A, "Ideal" swab; *B*, beam swab with unloader; *C*, Kline swab with plunger valve; *D*, Heeter's swab.

Special patented forms of wash rings, for use as packers about wash pipe, make use of babbitt or lead seals or glands packed with hydraulic packing. These are more effective and reliable in action than the simple disk packers illustrated in Fig. 197 but serve a similar purpose.

Plugging the Bottom.—To prevent sand and water from entering the space within the oil string, it is customary to plug the lower end of it with a wooden, lead or cast-iron "heaving plug" or "limit plug." The various forms of plugs have already been adequately described in connection with cementing operations in Chap. X.

Swabbing to Clear Perforations, Screens and Sand Pores.—The method adopted for placing the oil string or liner often leaves the perforations or screens clogged with clay or sand. If often happens also, unless the mud can be washed from the well by circulating clear water, that the walls will be plastered with clay and the rock pores clogged so that oil does not flow freely. In such cases the application of a swab will usually

remedy the condition by drawing the mud into the casing so that it can be bailed out.

The swab (see Fig. 198) is a rubber-faced hollow cylinder with a pin joint at the upper end to connect with the drilling tools, and on the lower end is placed a check valve opening upward. The steel body of the tool is constructed of perforated tubing, the fluid having access to the inside of the rubber cylinder through the perforations. The rubber sleeve can be expanded to fit snugly within the casing by compressing it longitudinally. This is accomplished by tightening the pipe coupling on the lower end against the metal ring which supports the rubber cylinder.

(*Courtesy of Guiberson Corporation.*)

FIG. 199.—Guiberson basket-type swab.

The swab is lowered slowly to the bottom of the well on the drilling cable, the well fluid lifting the check valve, passing up through the inner tube and into the space above, through holes drilled in the wrench squares. On reaching bottom, power is applied and the swab is rapidly pulled out of the well. The check valve prevents the well fluid from again passing through the swab, and it is pushed ahead of the latter to the surface. The rubber cylinder is only slightly smaller than the inner diameter of the casing, and when the fluid pressure is brought to bear against the inner surface of the rubber (through the perforated supporting pipe), it is expanded until it presses firmly against the casing, effectively preventing leakage of fluid around the cylinder. Because of the small clearance between the rubber and the pipe, it is important that the inner surface of the casing be free from indentations and blisters; otherwise the rubber cylinder will be rapidly destroyed and there will be considerable resistance to movement.

Figure 199 illustrates a popular type of swab which comprises a flexible "basket" construction instead of the usual rubber cylinder. The hollow supporting mandrel contains an upward-opening valve. The bottom of each flexible swabbing element, with its supporting basket of heavy wire, is fastened rigidly to the mandrel, but the upper part is free to expand or contract as pressure conditions may dictate. When lowered through fluid, the valve opens and upward pressure compresses the baskets. When lifted, the fluid pressure closes the valve and expands the baskets so that they press firmly against the inner surface of the casing or tubing through which they are operated.

In addition to providing a means of rapidly and effectively removing all fluid from the well, application of the swab creates a reduced pressure within the casing, which draws oil, loose sand and clay through the perforations. The perforations and screens are thus cleared of obstructions and a flow of oil into the well is established. After the swab has been removed, the bailer is lowered to remove sand and mud which have been drawn through the perforations.

It is important in operating the swab not to trap more fluid above it than the power is able to lift or than the swab is designed to support. An improved type of swab is equipped with a valve combining the principles of a vertical check valve and a pop safety valve, which automatically releases any excess fluid beyond that for which the valve is set.

"SHOOTING" FOR PRODUCTION

The use of explosives in stimulating production is widely practiced in regions where the producing strata are hard, close-grained rocks which offer unusual resistance to the flow of oil into the well. Limestones are characteristic of this class and are usually shot with a charge of nitroglycerin, blasting gelatin or dynamite as soon as the well is completed, to open channels through the reservoir rock and to stimulate the flow.

Nitroglycerin, which is the explosive generally employed for this purpose, is charged into long, tinned sheet-iron cylindrical containers called "torpedoes" or "shells." From 5 to 300 qt. of explosive are used, depending on the nature and thickness of the stratum to be shattered. The shells are usually about 1 in. smaller in diameter than the casing through which they are to be lowered and vary in length according to the capacity desired. Capacities are commonly 10, 20 or 30 qt., and as many shells will be used in the "shot" as may be required to make up the total quantity of nitroglycerin considered necessary. The shot is customarily submerged in from 100 to 200 ft. of water to serve as "tamping" for the charge. This causes the explosive to expend its energy laterally and downward instead of upward. The well casing should be drawn up above the level of the well fluid if possible. The casing is occasionally ruptured at the fluid surface unless this is done.[7]

The upper end of each shell is equipped with a bail by means of which it is suspended from a hook on the end of a steel or tarred manila torpedo line, which serves to lower it from the surface to the desired point in the well. This line is carried over a small pulley, supported in a stationary position a few feet over the mouth of the well, and is wound on a special reel which is customarily attached to the flywheel of the engine, though it is also equipped with a crank and supports so that it may be mounted separately and operated by hand. The hook on the end of the torpedo line which supports the shell is so designed that on lowering it slightly

after the shell rests on bottom, the hook is detached from the torpedo bail so that it can be withdrawn, leaving the shell in the well.

The shells are ordinarily filled while suspended in the well so that the upper end is at a convenient level for pouring in the glycerin from the 10-qt. cans in which it is shipped from the manufacturers. After filling, the shell is washed off with water to remove any drops of glycerin that may have splashed out of the container.

Ordinarily the well will have been drilled entirely through the oil-bearing stratum or zone and to a slight depth below into the underlying formations. Since the shot is generally confined to the space within the well immediately opposite the oil stratum, it will be necessary to support the first shell lowered, at the proper distance off bottom, so that the charge will not extend below the oil zone. In order to accomplish this, the first shell placed in the well will have attached to its lower end an "anchor" of proper length, composed of tubing about 1¼ in. in diameter. When the first shell has been lowered until the anchor rests on bottom, other shells are loaded and lowered successively so that they rest end to end on the first shell. If the shells are much smaller in diameter than the hole, each should be equipped with a disk at the upper end nearly as large in diameter as the casing, to prevent two shells from being placed side by side in the well instead of end to end (see Fig. 201).

The uppermost shell is often equipped with a detonating device consisting of a sheet-metal disk of about the same diameter as the shell, supported in a horizontal position by a vertical firing pin, which bears upon a fulminate-of-mercury blasting cap[7] (see Fig. 200). A common method of firing the charge is to drop a "go-devil," a short bar of cast iron, from the surface, striking the disk and detonating the fulminate cap. An alternative method of firing involves the use of a "squib," of which there are several types. Figure 202 illustrates a "jack" squib, which consists of a double-walled tin shell, 2 in. in diameter and from 3 to 5 ft. in length, and containing ½ pt. of nitroglycerin or a stick of dynamite. Several feet of waterproof fuse, with a fulminate-of-mercury cap at the lower end, are wrapped about the tube containing the explosive. The end of the fuse projecting from the upper end of the squib is ignited and the device is dropped into the well on top of the charge. The length of fuse must be varied to correspond with the depth of the hole and the depth of well fluid on top of the charge but varies from 2 to 10 ft. Other types of squibs not so commonly used as the jack squib are the "line" squib and the "bumper" squib. The former consists of a short shell weighted so that it will sink freely through the well fluid and equipped with a firing head and three percussion caps. The line squib is lowered on a wire until it rests on the charge, and a nipple or short length of pipe is dropped over the wire to fire the squib. The bumper squib consists of a small shell filled with nitroglycerin and equipped with a firing head and

pin and a percussion cap. A 4-ft. length of 2-in. pipe is attached to the top of the squib in such a way that the firing head is exposed in the lower end of it (see Fig. 203). The wire on which the squib is lowered into position passes freely through the bail on the upper end of the pipe, and a heavy weight, such as a sash weight, is fastened on the end of the line below the bail. As the squib is lowered, the sash weight supports

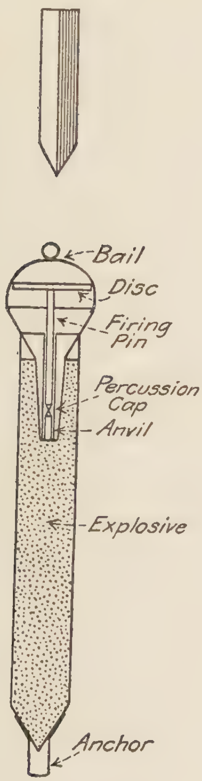


Fig. 200.—Impact detonating device for use with "go-devil."

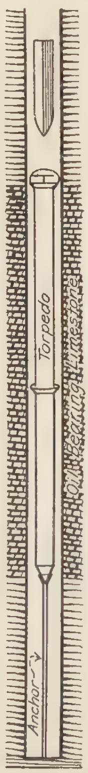


Fig. 201.—Illustrating use of torpedo in "shooting" oil-bearing formations.

(*After W. H. Jeffery.*)
Fig. 202.—Jack squib.

(*After W. H. Jeffery.*)
Fig. 203.—Bumper squib.

the bail, but when the squib comes to rest on the charge, release of tension in the line at the surface permits the sash weight to descend, striking the firing head and detonating the charge.

Occasionally, when the well does not extend below the oil-producing stratum, the metal containers for the explosive are dispensed with. The nitroglycerin is in this case lowered in a specially designed container resembling a dump bailer (see page 356), which permits the explosive to flow out into the well when it reaches bottom. Successive trips are

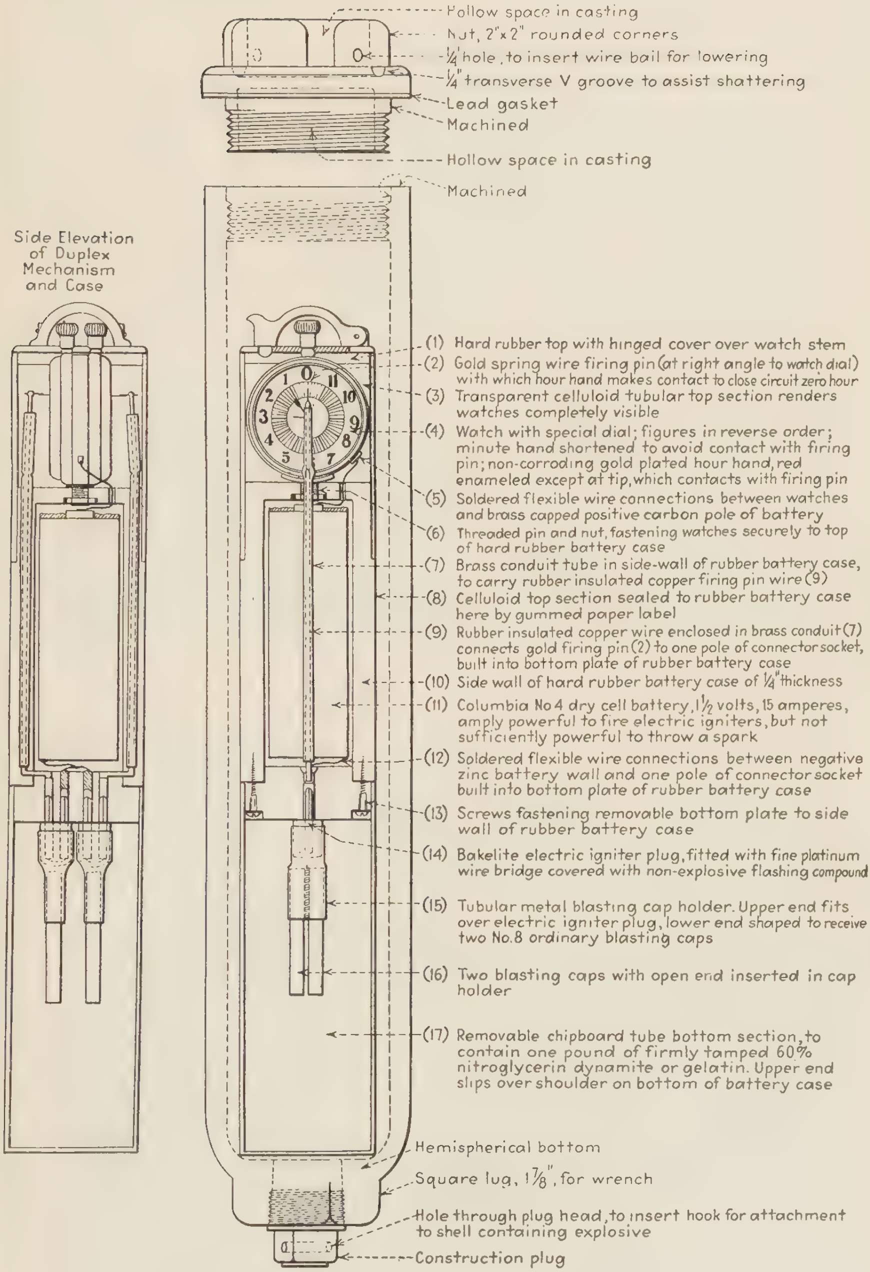
made until the hole is filled with the glycerin up to the top of the oil zone, and the charge is then fired with a squib.

Many operators prefer to fire explosives electrically, and for this purpose the last shell lowered is equipped with an electric blasting cap and is lowered on the sand line to which is bound an insulated copper wire. When all is in readiness, a blasting machine at the surface sends a current of electricity down through the copper wire and fires the charge. This method of firing is preferred in cases where the walls of the well tend to cave. The casing is customarily drawn up several hundred feet above the explosive after the shells are in position, and, if the walls cave, the charge may be covered with mud or débris so that a go-devil or squib cannot reach it. With electric firing, unless the wire is broken, the charge may be fired even though the walls do cave.

The Zero Hour electric bomb, illustrated in Fig. 204, widely used in detonating explosives in well shooting, embodies a charge of dynamite, two blasting caps and electric igniters, a battery of dry cells which furnishes electric current and a control timepiece. The entire mechanism is enclosed within a substantial brass casing which is secure against leakage under high hydrostatic heads. The watch may be set to close an electrical contact which fires the charge at any desired time with a safety interval of from 1 to 22 hr. The "duplex" bomb, designed for greater certainty in operation, is equipped with a double set of caps and igniters and two synchronized timepieces. If necessary, the several parts of this bomb may be enclosed within a tube only 1½ in. in external diameter. A device of this character embodies most of the advantages of electric detonation without the added complexity and expense of providing an electric circuit extending to the surface.

Because of the sensitive character of nitroglycerin, every precaution must be taken in handling it to prevent accidental explosion. It should not be transported in leaky cans. Undue friction and jarring of the containers should be avoided. The empty cans should be disposed of. Loading and firing nitroglycerin are customarily done by skilled "well shooters," who undertake full responsibility for the work on a contract basis. The average cost of such work in the fields of Ohio, Illinois and Indiana is about $3 per quart.

Special care must be taken in placing the shot so that it does not damage the casing and other well equipment. Accurate depth measurements are necessary in order to place the charge at just the proper point in the well, otherwise the cap rock overlying the oil zone may be fractured, permitting oil and gas to escape or water to enter the oil-bearing rocks. The line on which the explosive is lowered should be "flagged" or marked 100 ft. or so above its lower end, and on drawing the line out of the well after lowering a shell the lower end below the flag should be hoisted out slowly. Occasionally the torpedo-line hook does not disengage itself



(*Courtesy of Zero-Hour Bomb Co.*)

FIG. 204.—Zero-Hour electric bomb.

from the torpedo bail, and, if the shell is hoisted back to the surface and permitted to strike the line pulley over the well, a disastrous explosion might result.

Nitroglycerin free from excess acid will not explode at temperatures normally encountered in oil wells, but slow decomposition results at temperatures above 140°F., and in some deep wells the explosive apparently undergoes decomposition and explodes spontaneously after a period of from 2 to 100 hr. In the deep territory of the Ranger field, shots are customarily allowed to explode in this way without the aid of detonating devices.

A powerful shot of nitroglycerin exploded in a well probably results in the formation of a large cavity with fractures extending out in all directions. Expansion of the gases of explosion causes a rush of fluid, mud or dust and rock fragments from the well, which is often accompanied or followed by a flow of oil and gas. Owing to the restricted diameter of the well, there is a surprising delay in the effect of the explosion at the surface after the charge is fired. In a deep well, vibration of the casing gives warning of the explosion many seconds before the rush of gas reaches the surface and before the sound is heard. In expectation of a shower of water, oil, gas and débris from the well, the rig should be in the sole possession of the shooter when the charge is fired and he must seek a place of safety as promptly as possible thereafter.

Additional data on well shooting are found in Chap. IX.

CONTROL OF HIGH-PRESSURE WELLS

On drilling into a stratum containing oil or gas under high pressure, precautions must be taken against loss of control which might result in waste of oil and gas and serious damage to the well and its equipment as well as to surrounding property. Preventive measures are of two sorts: (1) the use of methods which prevent the destructive forces from becoming operative, and (2) the provision of safeguards which will make possible their control if they do become operative.

A high-pressure well out of control may prove exceedingly destructive. Violent ejection of the well fluid, perhaps accompanied by flows of sand, oil and gas, sometimes shatters the derrick, occasionally burying the drilling equipment (see Fig. 205). The drilling tools, rotary drill stem, and at times even the heavy casings, have been lifted bodily out of the well by the forces developed (see Fig. 206). Lack of control at such times often permits large quantities of sand to heave into the well, or the walls may cave or the casing collapse, necessitating redrilling or, in extreme cases, even abandonment of the well. Blow-outs of high-pressure gas flowing around the outside of the well casings occasionally form craters which fill with water or oil and completely engulf the rig and its equipment. Oil jetted high into the air from the well is caught by the wind

and sprayed over the surrounding terrain, carrying destruction to trees and crops and necessitating repainting of buildings. At such times, fire

Fig. 205.—Destructive blow-out of drilling fluid from a well on encountering a high-pressure gas zone, Santa Fe Springs field, Calif.

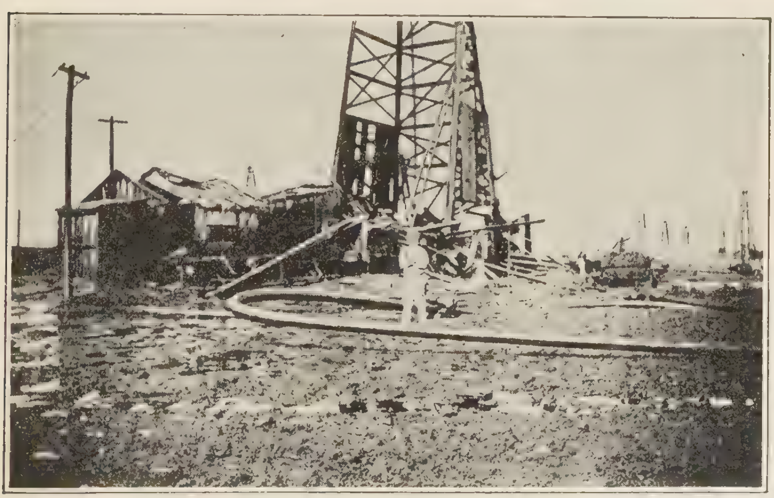
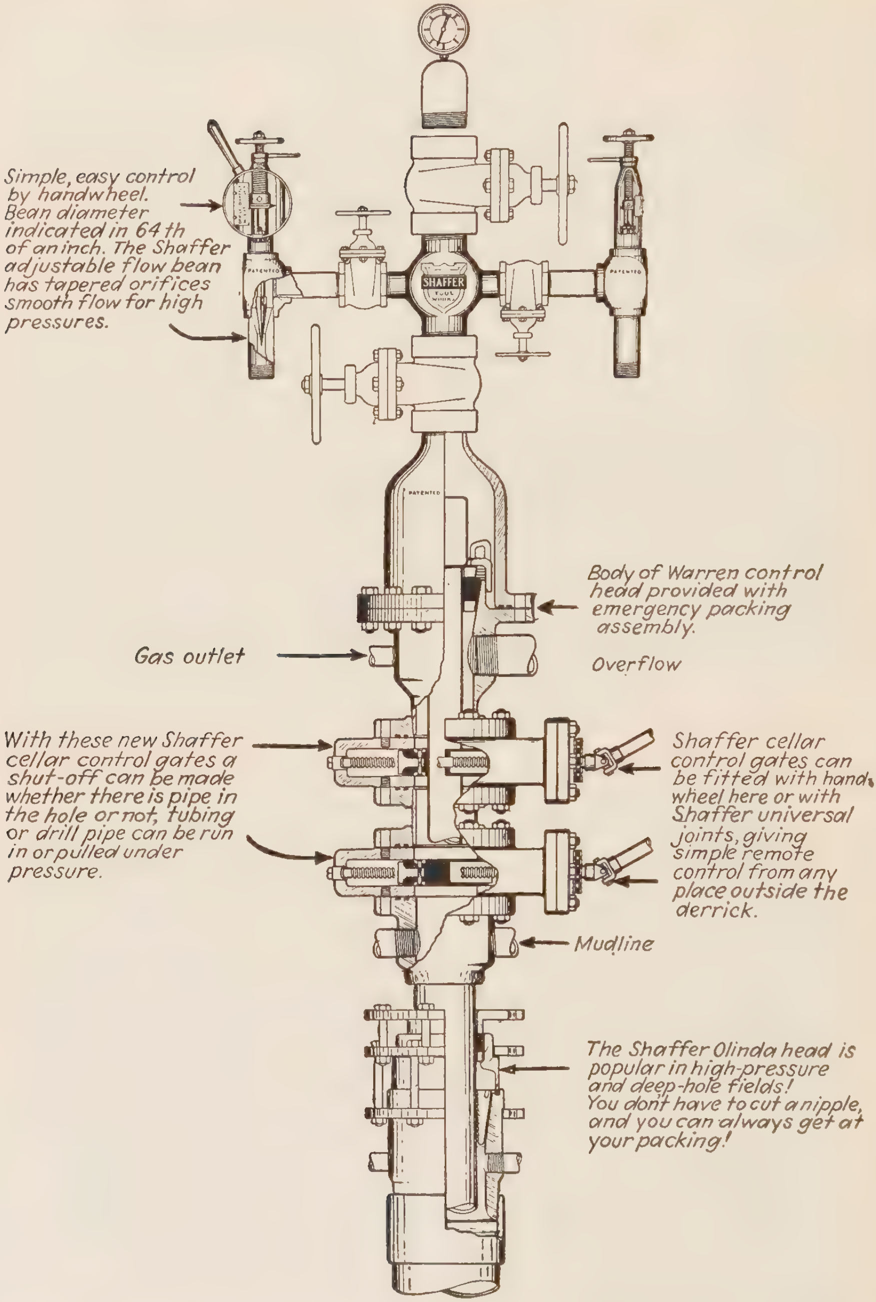


Fig. 206.—Illustrating wreckage of surface equipment after a blow-out. Note coiled rotary drill pipe in foreground.

frequently adds to the destruction. A static spark resulting from friction of gas at the casing head; a spark caused by the striking of metal on metal, or rock on metal; or a flow of gas coming into contact with the boiler fires,



(*Courtesy of Shaffer Tool Works.*)

Fig. 207.—Assembly of cellar control gates, special heads, Christmas-tree valves and fittings and adjustable flow beans.

the forge or other naked light—and the well and everything reached by the oil is converted into a mass of flame. Such conditions sometimes develop in so brief a space of time that they become a menace to the lives of the drillers. Once out of control, the flow of oil and gas may continue for days, weeks or even months, the damage wrought to the well equipment and difficulty of approach often making possible remedial measures ineffective.

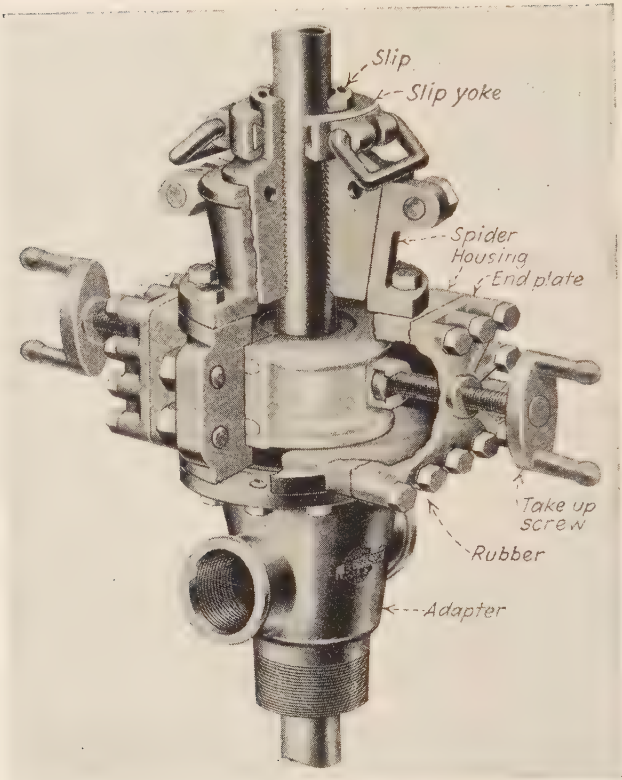
HIGH-PRESSURE WELL-CONTROL EQUIPMENT

When drilling in locations where high-pressure conditions may develop within the well, precautions should be taken in advance of actual need, that will permit of promptly shutting in the well at the casing head. The casing head, valves, fittings and other control devices used for this purpose must be of sufficient strength to withstand the maximum pressure to which they may be subjected. Formation pressures encountered in some of the recently drilled deep fields of California and Oklahoma have exceeded 2,000 lb. per square inch, and in order to provide an ample factor of safety some of the heavier well-head fittings are designed to withstand test pressures as great as 6,000 lb. per square inch.

A well drilled in high-pressure territory will usually be equipped with a blow-out preventer which can be quickly closed about the rotary drill pipe within the annular space between it and the casing. This is attached to the casing below the derrick floor so that drilling operations may be conducted through it. The Shaffer control gate, illustrated in Fig. 207, is designed to accomplish the same end. The Guiberson oil saver serves a similar purpose when tubing is being lowered into a high-pressure well (see Fig. 208). These devices are described in greater detail below.

It is important that suitable means be adopted to support the various strings of casing in the well and to close the annular spaces between telescoping strings by devices that will be capable of withstanding the high pressures to which they are often subjected. Frequently too, they must sustain a large part of the weight of the casing and must therefore be provided with adequate foundation supports. Figures 209, 211 and 212 illustrate a variety of different types of control casing heads designed to accomplish these purposes.

After completing the drilling of a high-pressure well, and before bringing it in, it is customarily equipped with suitable valve equipment above the casing head to control flow of oil and gas from the well during the subsequent period of natural flow. An assemblage of valves designed for this purpose is called a "Christmas tree." Figures 207, 210, 211 and 212 are illustrative of different representative Christmas-tree assemblies. Figure 211 presents a sketch of typical well-head fittings and valves used by a large company operating in the California fields. Five telescoping strings of casing are used in this particular installation, in addition to a column



(Courtesy of Guiberson Corporation.)

Fig. 208.—Guiberson tubing oil saver.

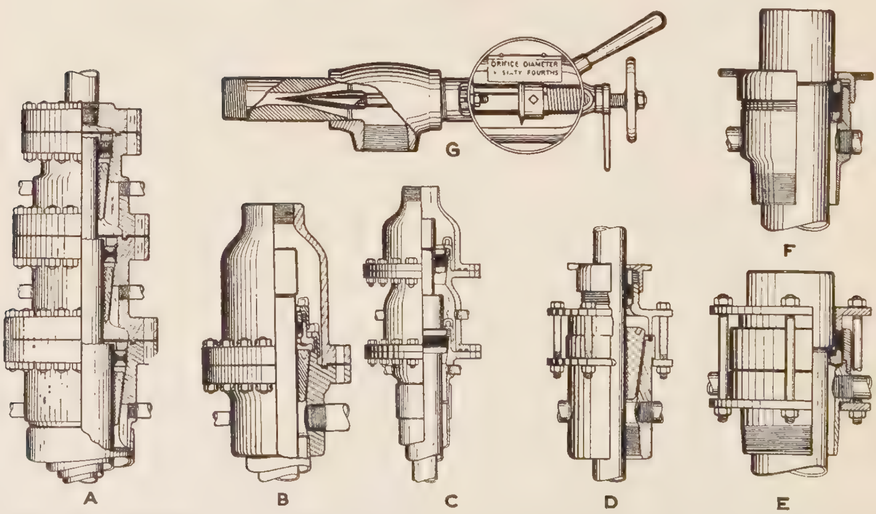
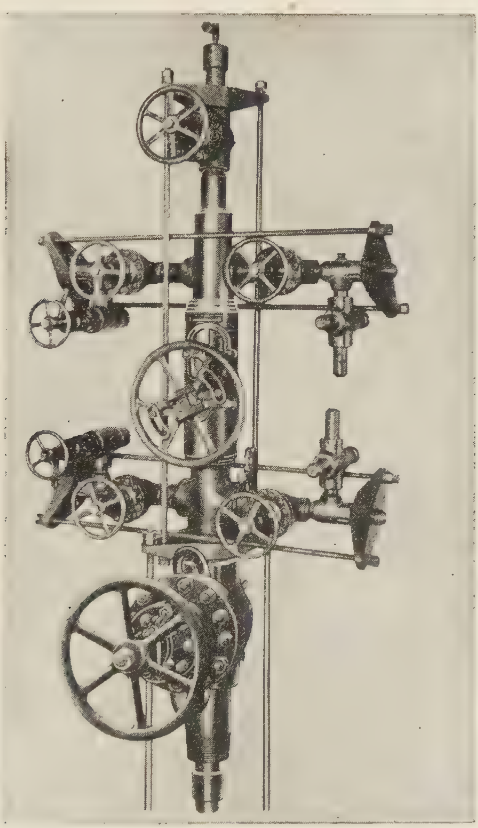


Fig. 209.—Flow bean and various types of casing heads manufactured by Shaffer Tool Works.

A, spool-type head; *B*, Warren-Olinda head; *C*, Warren double-cap head; *D*, Olinda head; *E*, Western head; *F*, Athens head; *G*, Shaffer adjustable flow bean.

of flow tubing. The assemblage of valves and fittings within the cellar shows the means adopted for closing the annular spaces between strings and preventing flow of fluids between. High-pressure valves and connecting nipples permit of venting pressures between any two columns of pipe when necessary. The Christmas-tree assembly above the derrick floor is similar to that pictured in Fig. 212. A special head closes the

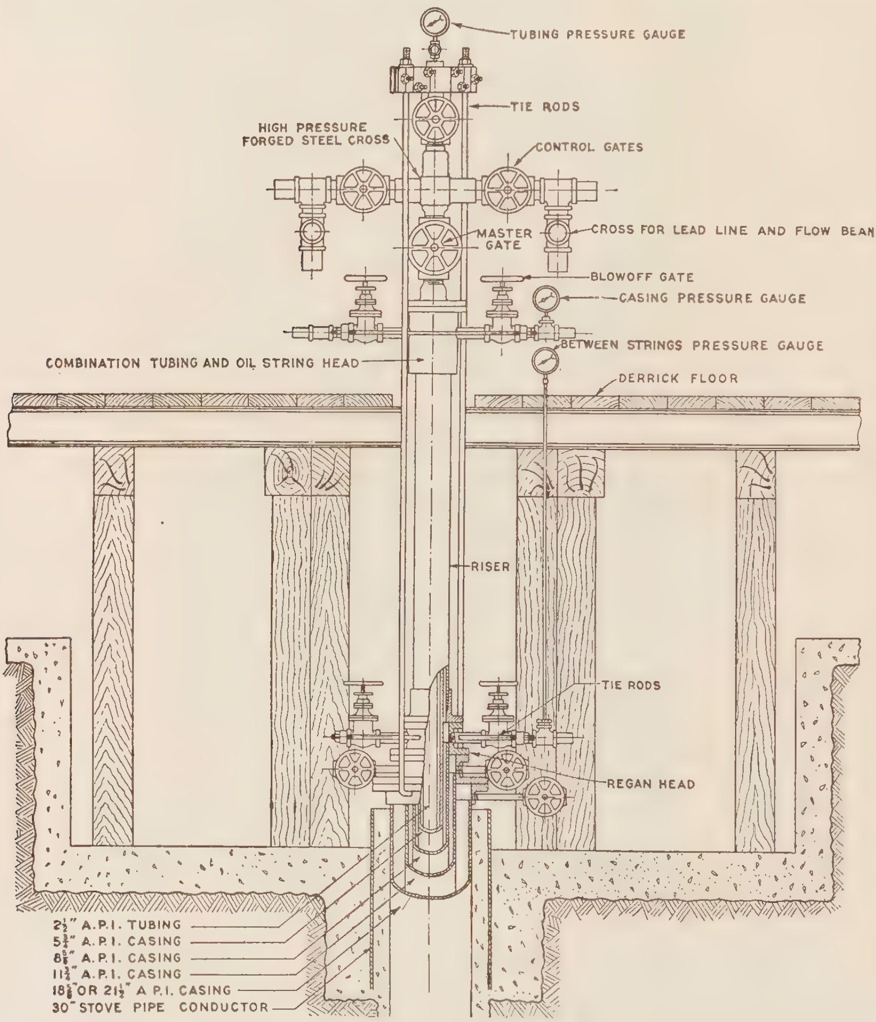


(*Courtesy of Hughes Tool Co.*)

FIG. 210.—Hughes Christmas-tree hook-up of double flow lines, Brown retractor head master valve, flow-line valves and Hughes flow beans.

space between the flow tubing and the inner string of casing. Side outlets from this head permit of drainage of "casing-head gas" if desired. A pressure gage on one of these flow lines indicates the casing-head pressure. Immediately above the head is the master gate. This is normally left open, being closed only in an emergency or when necessary to replace one of the upper control valves. A high-pressure forged-steel cross connects immediately above the master gate, the upper and two side outlets of the cross being equipped with high-pressure control gates. Flow of oil and the associated gas is ordinarily through either or both of

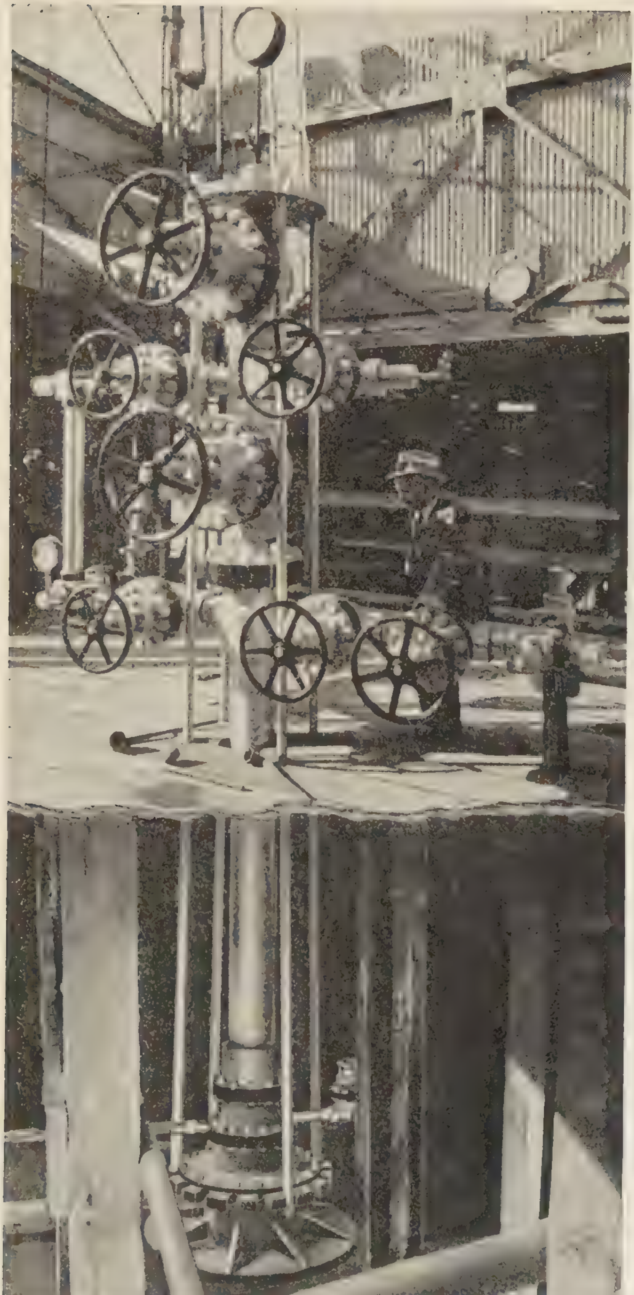
the side outlets of the cross. The upper valve serves as an additional control at such times as it may be necessary to allow the well to blow, or to permit excess oil and gas, beyond what can be taken care of by the side outlets, to escape. In the case of exceedingly high pressures it may



(*After T. E. Swigart in Am. Petroleum Inst., Bull.* 202.)

FIG. 211.—Sketch of typical well-head fittings used on a high-pressure well in the Ventura field, California.

be unsafe to shut in the well completely. A pressure gage on the upper outlet indicates the tubing-head pressure. The side outlets from the forged cross are equipped with swing connections and dead-end nipples which cushion the valves and fittings against vibration and sand scouring, resulting from sudden changes in direction of flow. The scouring



(*Courtesy of Regan Forge and Engineering Co.*)

FIG. 212.—Casing-head and Christmas-tree fittings: a high-pressure installation in the Kettleman Hills field, California.

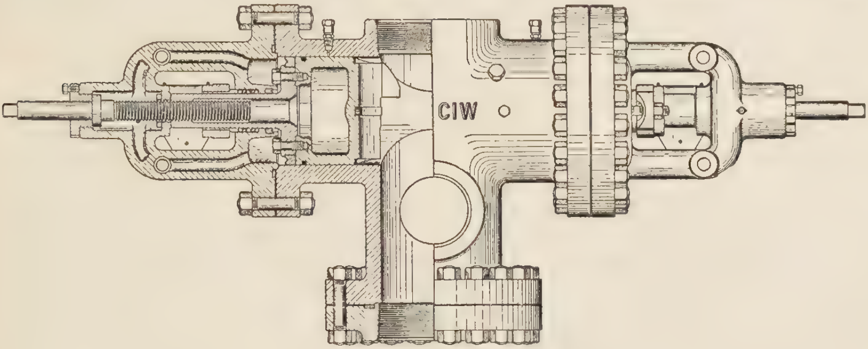
effect of sand carried by the oil may necessitate frequent replacement of valve parts and fittings. In each "lead line," a "flow bean" may be placed. This is nothing more than a constriction in the line provided for the purpose of restricting flow or maintaining any desired amount of back pressure on the well. The flow bean may be simply a block of metal supported in the path of flow by suitable fittings and having a small hole bored longitudinally through it. Apertures as small as ⅛ or ¼ in. may be used when a considerable back pressure is required on a high-pressure well. A preferred type of flow bean is one in which restriction of flow is accomplished by means of a needle valve permitting close adjustment and variation of the size of aperture (see Fig. 209*G*).

The Control Casing Head.—For use on wells which are expected to encounter high pressures, drilled with cable tools, a control casing head is often employed (see Fig. 213). This consists of a heavy casting in the form of a four-way tee which screws on the top of the working string of casing, the space between this and any larger string that may be in the well being closed with a packing ring screwed into the larger casing head. A special cylindrical valve, operated by a stem extending through a stuffing box in one of the side outlets, may be adjusted by a quarter turn to close either the top or bottom outlet of the tee, the side outlet being always open. A groove cut in the valve, large enough to admit the drilling cable, permits it to close when the drilling tools or bailer are in the well, without injury to the cable or sand line. By providing a 20-ft. extension of the valve stem, the valve may be manipulated from outside of the derrick. With the valve turned so that both upper and lower outlets of the tee are open, drilling operations may be conducted without interference. In the event of a sudden flow of fluid from the well, with the tools either in or out, by a quarter turn of the valve the well will be shut in, or the flow may be diverted through the side outlet and through a connecting lead line to a tank or sump.

FIG. 213.—Control casing head.

The Blow-out Preventer.—A device known as a "blow-out preventer" is widely used on rotary-drilled wells to prevent the circulating fluid from being forced out of the hole when it is expected that high-pressure sands will be encountered. This is a special form of casing head which is screwed on top of the last string of casing landed, or cemented in the well. It is equipped with a pair of sliding gates which close about the rotary drill stem and pack off the space between it and the well casing (see Fig. 214). The side outlets provide a means of connecting 6-in. pipe with the space between the casing and the drill stem. A gate valve provides the necessary control of each outlet. The gates are ordinarily kept open, but in the event of a threatened blow-out are closed about the drill pipe, preventing further escape of the well fluid. Each gate is controlled by a separate stem operating through a threaded nut and stuffing box, such as are used on an ordinary gate-valve stem. An extension of the stem permits of operating the device from the outside of the derrick. The steam-controlled blow-out preventer, illustrated in Fig. 214, requires only the opening of a valve on a connecting pipe at a safe point outside the derrick to close the annular space about the drill pipe. A back-pressure valve in the drill stem prevents mud from blowing out

through the stem, and with a blow-out preventer to pack off the space between the stem and the casing the well is securely shut in until the pressure can be killed with mud, or until provision can be made for taking care of the flow. If cable tools are employed, the blow-out preventer can be used effectively in packing off the space



(*Courtesy of Cameron Iron Works.*)

Fig. 214.—Cameron fluid-closing, manual-opening blow-out preventer.

between two strings of casing. In connection with a gate valve or control casing head on the inner casing, through the open gate of which the cable tools may be operated, ample security against blow-outs is afforded.

The Oil Saver.—Various devices known as "oil savers" are available for closing in the top of an ordinary casing head in such a way as largely to prevent the escape

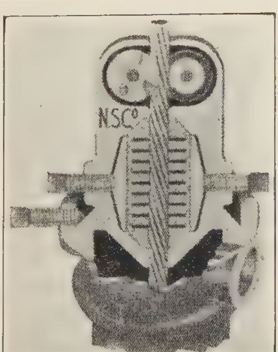


Fig. 215.—Oil saver, roller type.

Fig. 216.—Oil saver, barrel type.

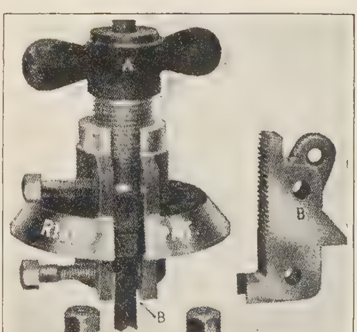


Fig. 217.—Rigby oil saver.

of fluid under pressure about the well mouth, yet permitting free movement of the drilling cable. These are of two general types: (1) one in which the cable works through a gland stuffed with hydraulic packing (see Figs. 215 and 217), and (2) one in which the cable is enclosed within a long, polished working barrel passing through

a suitable stuffing box (see Fig. 216). The latter is similar in principle to the circulating head described in connection with the standard circulating system of drilling (see page 184). The ordinary forms of oil savers are simply held in position in the casing head by set screws and are not absolutely secure against leakage if subjected to great pressures. They serve, however, to divert oil which may flow from the well while drilling is in process, through the side outlets of the casing head into the lead lines connecting with the storage tanks or sumps.

CONTROL OF HIGH PRESSURE BY THE USE OF MUD-LADEN FLUID

In controlling high-pressure gas, the best plan is to deal with the menace at its source and prevent the gas from entering the well. This can ordinarily be accomplished with the aid of mud-laden fluid. We have seen that the opportunity afforded to use mud-laden fluid in sealing off and controlling high-pressure sands is one of the principal advantages of the modern hydraulic rotary and standard circulating methods of drilling.

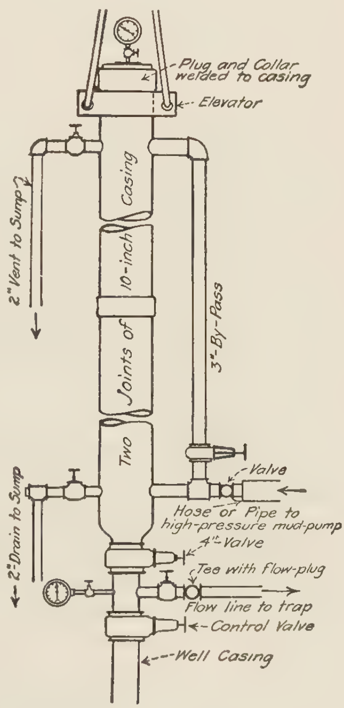
The effect and manner of application of mud-laden fluids in ordinary drilling practice have already been adequately described (see page 227), but descriptions of certain special applications of the mudding process in controlling high pressures have been reserved for the present chapter.

If the well is being drilled by rotary methods and high-pressure gas is encountered, the circulating fluid is at once thickened by the addition of clay to the mud pit, drilling being discontinued for a time, if necessary, to allow ample opportunity for the mud to seal the pores of the high-pressure stratum. Every precaution must be taken to avoid a blow-out, or ejection of the fluid from the hole. The ability of the circulating fluid to resist the gas pressure and prevent its admission to the well depends chiefly upon the hydrostatic head developed. Ordinarily about 15 per cent heavier than water, each 100 ft. of mud-fluid pressure is equivalent to about 50 lb. per square inch. This can be increased to as much as 60 lb. per square inch by addition of clay until the fluid has a density of 1.4. At a depth of 1,000 ft., the mud fluid may therefore exert a pressure of 600 lb. per square inch. If a gas sand encountered at this depth is under a greater pressure, obviously gas will enter the well; and unless additional pressure is applied or the outlet from the well is closed, the fluid will be violently ejected. If there is danger of this, it may be necessary to resort to the use of ground barite or hematite instead of clay. With heavy minerals such as these, fluid suspensions having a density more than twice that of water and developing static pressures of upward of 90 lb. per square inch per 100 ft. of depth can be prepared.

If gas enters and mixes with the circulating fluid, the density of the latter may be considerably reduced by gas occlusion, thus reducing the hydrostatic head on the well and the effectiveness of the mud in resisting the gas pressure. Fresh fluid should be circulated continually through the well, and the mud should be agitated on reaching the surface to free it from occluded gas before again pumping it into the well. Blow-outs

sometimes occur during removal of the drill stem from the well. Displacement of fluid by the stem results in considerable subsidence of the fluid level when the stem is withdrawn, with consequent decrease in the hydrostatic head opposing a high-pressure sand in the bottom. More fluid should be introduced at such times, or the mud should be thickened.

Mudding under Pressure.—If a high-pressure sand is suddenly encountered with rotary tools in the well and there has been insufficient time to thicken the mud fluid to resist it properly, at the first sign of instability of forces within the well the blow-out preventer is closed and drilling is discontinued. The mud in the slush pit is thickened by the addition of clay until a mixture as thick as the pump will handle is obtained. As this thicker mixture is pumped into the well through the drill stem, the pressure builds up until a sufficient pump pressure is added to the natural hydrostatic head to offset the pressure in the sand. Excess pressure beyond this point forces the well fluid into the sand, and, as the fluid is absorbed, the sand pores gradually become clogged with clay until the openings by which the gas enters the well are closed. By this time the heavier mud will also have considerably increased the normal hydrostatic head so that the pump pressure can gradually be reduced; the blow-out preventer is then cautiously opened and circulation is resumed. Slow drilling with frequent rest intervals for mudding under pressure will usually enable the tools to penetrate the high-pressure sand without loss of control.



(*After H. J. Steiny, California State Mining Bureau, Department of Oil and Gas.*)

Fig. 218.—"Lubricator" for use in mudding high-pressure wells.

Use of the "Lubricator."—If the drilling tools are out of the hole when a blow-out occurs and it is possible to close the outlet either with the aid of a blow-out preventer or a control casing head or both, a somewhat different procedure must be adopted. The problem now presented is that of placing more mud in the well so that greater hydrostatic resistance may be exerted by the well fluid. In order to accomplish this without releasing the pent-up forces within the well, a device called a "lubricator" is rigged above the casing head. This consists of two joints of casing about 10 in. in diameter, connected by a coupling, with a tee at the bottom, which, in turn, is connected by a nipple to the top outlet of the control casing head or valve *A* (see Fig. 218). Near its upper end, the 10-in. casing connects through a reducer to a 2-in. pipe which, by means of two elbows and a nipple, is led down at one side of the 10-in. casing to about the level of the derrick floor, and thence to the mud pit. A control valve *B* is placed in this 2-in. line at some convenient point outside of the derrick. A 3-in. line connects the side outlet at the lower end of the 10-in. pipe with a high-pressure slush pump. All pipe and fittings should be capable of withstanding heavy pressures.[15]

With valve *A* closed and *B* open, a thick mud is prepared in the mud pit and pumped through the 10-in. casing until it overflows through the 2-in. line which

returns the excess to the mud pit. The pump is then stopped, valve *B* is closed and *A* is opened. The mud in the lubricator, by reason of its excess of density over that of the well fluid, sinks through the casing to the bottom of the well. Valve *A* is then closed, *B* is opened and the process is repeated until the well fluid has been greatly increased in density and a considerable depth of thick mud has settled to the bottom of the well. Pump pressure may then be applied by closing valve *B*, opening *A* and operating the pump, thus forcing the thickened fluid to flow into the high-pressure sand, depositing its clay in the sand pores about the walls of the well. After the formation ceases to absorb the well fluid under high pump pressure, the pump is stopped and valve *B* is cautiously opened. If the fluid is not ejected, it may be assumed that the high-pressure sand has been effectively sealed and the lubricator is removed and drilling continued.

If the cable tools are used, alternate drilling and mudding in this manner will make it possible to penetrate the high-pressure sand and continue to greater depths if desired; but care should be taken not to permit too low a fluid level on the sand, or the pressure may clear the sand pores of mud and cause a recurrence of the difficulty.

Use of the Circulating Head in Controlling High-pressure Wells with Mud-laden Fluid.—The circulating head and mud-pumping equipment described in connection with the standard circulating system of drilling offers a convenient means of controlling high pressures in wells drilled with cable tools (see page 184). If the presence of a high-pressure sand is known or expected, the circulating head should be placed on the casing before penetrating it. In this device the space about the drilling cable within the head is packed off with a stuffing box. If high-pressure gas is encountered, heavy mud is pumped through the side outlets of the head, and pump pressure is maintained until the sand is sealed. If cable drilling is in progress and an unexpected flow of high-pressure gas is encountered, the pressure may be brought under control with the aid of a lubricator and a circulating head is placed on the casing to take care of further mudding before drilling is resumed.

Placing Mud-laden Fluid in a Well That Cannot Be Shut In.—It will occasionally happen that a well cannot be shut in, either because the casing has not been landed and gas finds its way to the surface outside of the casing, or because it would be unsafe to subject the casing and fittings to the prevailing pressure. In such a case it would be impossible to use the lubricator in the manner described above and another method of introducing the fluid must be adopted.

Often, at some point above the high-pressure sand, there will be a conductor string landed, on which a tee casing head may be placed. A string of 2- or 3-in. tubing is lowered to bottom through the top opening of the tee, and the space around it is packed off so that it is secure against gas pressure. The lower end of the tubing is equipped with a back-pressure valve or a loosely placed wooden plug which can be forced out by pump pressure, while the side outlet of the tee is controlled by a gate valve. Mud is pumped down through the tubing to the bottom of the well, the gate valve being partially closed to prevent it from being blown out by the gas pressure until there is sufficient mud within the well to offset the pressure. The outlet may then be closed and pump pressure applied to force fluid into the sand.

If the gas pressure is not too high, mud may be introduced by setting the casing on bottom after the high-pressure sand has been penetrated, filling the casing with mud; and then lifting it slightly so that the mud rapidly rises in the space about the casing, inundating the gas sand. By this procedure the well is usually filled to a point between two-thirds and three-fourths of its depth, and the height of fluid is in many cases sufficient to offset the gas pressure. Unless there is a large clearance between the walls of the well and the casing, there is danger of the casing becoming frozen when this method is used, and in some instances collapse of the casing has resulted.

It may seem desirable or necessary at times to introduce mud-laden fluid at the surface into the space around the outside of the casing, or between two strings of casing. This should be avoided, however, if possible, since in flowing down the walls of the well the fluid often loosens much coarse material which settles about the collars and freezes the pipe.

Capping a Flowing Well

If a blow-out occurs and no control devices have been provided at the casing head, the well may get so far out of control that the flow of mud, oil and gas makes it difficult to attach a control head or valve on the casing. Since the well will continue to flow with great loss of oil and gas until checked in some way, it is necessary at once to undertake "capping" operations. This involves placing a valve of some sort on the outlet.

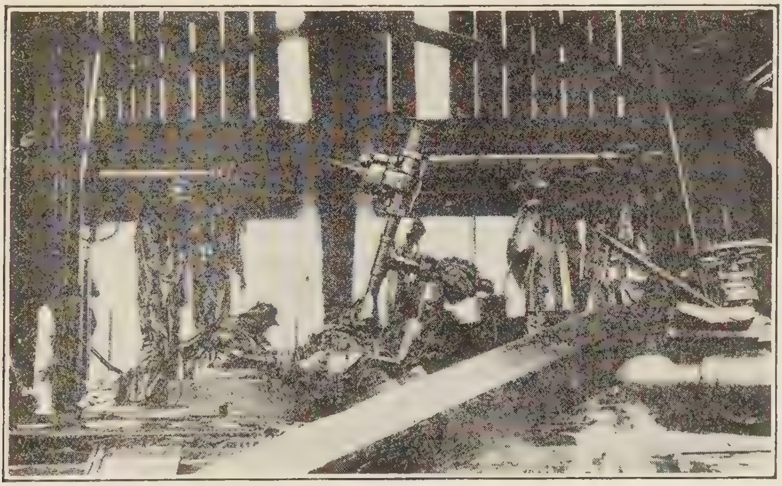


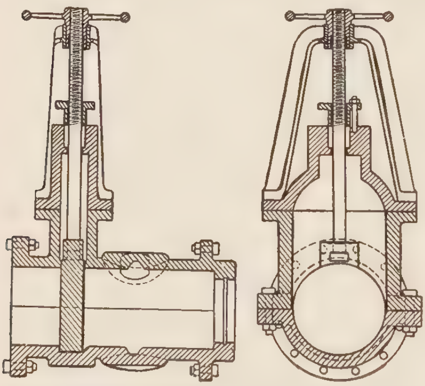
Fig. 219.—Capping a gusher.

The valve to be employed is of the flanged-gate type and should be of massive construction to withstand the high closed-in pressure to which it is likely to be subjected (see Fig. 211). This "master valve" is suspended over the mouth of the well in the derrick and is gradually lowered on a previously placed flanged connection on the casing, while the stream of gas and oil passes through the open gate (see Fig. 219). When the flanges have been bolted together, the gate is slowly closed until the well is brought under control. Additional control valves, fittings and flow connections such as are described on page 431 may then be connected above the master valve before the well is again permitted to produce.

Anchoring Casing and Control Valves.—The upward pressure exerted by gas enclosed within the casing by closing the outlet is in some cases great enough to place considerable strain upon the connections at the casing head. In some instances pressures have been sufficient to lift

the casing bodily out of the well. To offset this tendency, it is customary to anchor the control valves or casing head to the derrick sills with the aid of a heavy steel clamp and long bolts. In order to give additional security, some operators construct a heavy block of concrete about the casing below the derrick floor, embedding the anchor bolts in the concrete in such a way as to prevent the pipe from moving.

The Mortenson Well Capping Device.—In the case of gushers producing large quantities of oil and gas under high pressure, it may be difficult or impossible to attach an ordinary gate valve or control casing head in the manner described above. The great force of the flow sometimes makes the open end of the casing practically inaccessible. Or perhaps, the upper end of the casing has become damaged or is not suitably equipped to receive and support a heavy control valve. Under such conditions recourse may be had to the use of Mortenson capper (see Fig. 220). This is a massive gate valve built in sections, in such a way that it may be assembled about the column of casing without the necessity of making any screw connections or of lowering the valve through the flowing gas and oil. The capper is divided into two parts longitudinally and is bolted about the upper end of the casing with the shoulder at the lower end, just below the top coupling. The gate is withdrawn into its recess while the device is being placed on the casing so that it in no way obstructs the flow of oil or gas. If desired, it can be placed one joint below the upper end of the column with the upper joint of casing extending up through the valve, the upper joint being detached after the capper is in position. A groove in the lower end of the device provides a recess for hydraulic packing which bears against the pipe below the coupling and prevents leakage. Two circular side openings provide a means of attaching lead lines which are controlled by separate gate valves. The upper end of the capper is equipped with a flange and bolts for pipe connections, while a flange at the lower end provides a means of attaching anchor bolts the lower end of which are embedded in a block of concrete cast about the casing. The lower edge of the groove into which the gate fits is rounded in order to permit sand to be squeezed out of the groove as the gate is seated. The device is manufactured in several different sizes, varying in weight from 1,600 lb. for 6¼-in. casing to 3,600 lb. for 15½-in. casing.



(After Arnold and Garfias, U. S. Bur. Mines, Tech. Paper 42.)

Fig. 220.—Mortenson capping valve for controlling high-pressure wells.

Protection of Workmen about High-pressure Wells

It is obvious that considerable risk is attached to the conduct of work about high-pressure wells, and every precaution should be taken against accident. Excessive pressure may result in the failure of control valves or fittings about the casing head, which are shattered with explosive violence. A sudden rush of high-pressure gas, accompanied by mud or

oil, may wreck the derrick or force the drill stem or casings out of the well. The position of the derrick man in such an event is particularly dangerous. A safety device in the form of a wire-rope sling, which enables the derrick man to slide down one of the guy wires to safety, has been rather widely adopted in some of the California fields. The stems controlling blow-out preventers and control heads should be so extended that they may be adjusted in case of necessity from a point outside of the derrick.

Capping operations must often be conducted in the presence of large quantities of highly inflammable oil and gas, ready to explode or flash into flame on the slightest incitement. While natural gas is not poisonous or asphyxiating unless hydrogen sulphide is present, the mere absence of oxygen in an atmosphere so laden with methane and oil vapor may make work about the well difficult and even dangerous. The use of self-contained oxygen breathing apparatus about oil and gas wells under such conditions offers a possible solution for this difficulty. Every precaution must be taken against fire.

PREVENTION AND CONTROL OF OIL- AND GAS-WELL FIRES

The destruction wrought by the firing of a well producing large quantities of oil and gas under high pressure has been demonstrated in many fields. Aside from great losses of oil and gas from the burning of the well itself, the danger to other near-by wells and surrounding property usually requires prompt action in controlling and extinguishing it. The conditions attending such a conflagration present a problem in control of natural forces very difficult of solution. The column of flame may extend for several hundred feet into the air above the casing head (see Fig. 222). If the well produces more oil than the flames can consume while in the air, the surrounding terrain may be deluged with burning oil. The derrick and wooden portions of the drilling plant are rapidly consumed, and the metal portions are converted into a mass of twisted iron and steel. This and the intense heat prevent close approach to the casing head. The casings projecting from the well mouth are often so damaged that they offer little opportunity for shutting in the flow even though means of approach and control for the fire are possible.

Gas-well Fires.—Gas-well fires are easier to extinguish than oil-well fires, for the reason that the gas is completely consumed and the flame is confined to a well-defined column of no great thickness. The force of the flowing gas and scarcity of oxygen, except about the periphery of the ascending stream, usually prevent the gas from burning until it is well above the outlet. As the column ascends, however, air is drawn in and mixed with the gas so that it burns freely.

If the gas flow can be momentarily interrupted, it will usually be extinguished. It is customary to resort to the use of steam to accomplish this. A large volume of steam suddenly and forcibly applied immediately

above the casing head, against the stream of gas, cuts off the supply of oxygen necessary to support combustion and smothers the flame. Incidentally, the steam serves to cool the ascending vapors and metal objects about the well and casing head.

In combating gas-well fires with steam, a battery of portable boilers—frequently 20 or more—of the type used in furnishing power for drilling operations is assembled about the well at a safe distance. Steam pipes equipped with goosenecks terminating in flattened nozzles are connected with the boilers, pushed forward toward the fire and adjusted so that the nozzles will direct their jets of steam directly against

Fig. 221.—Lakeview No. 2 gusher, Sunset field, California.

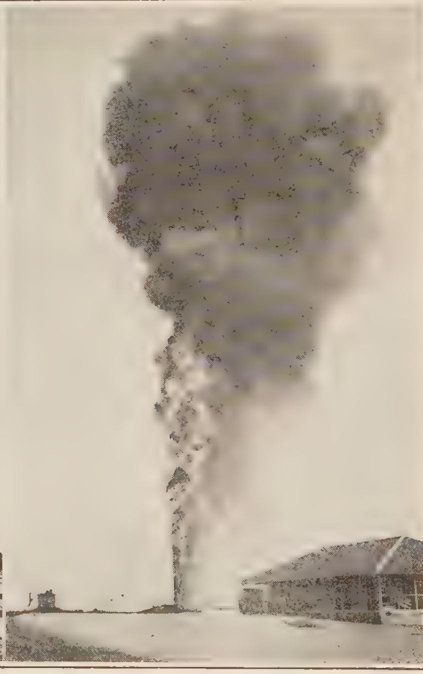


Fig. 222.—A gusher fire, Elk Hills field, California.

the outlet of the casing head. The boilers are fired and a supply of high-pressure steam is suddenly discharged into the fire from all sides and, if possible, maintained for several minutes after the fire is extinguished. Sprays of water similarly directed are sometimes successful, the water being converted into a blanket of steam on contact with the flame. A 40,000,000-cu. ft. gas-well fire near Monroe, La., was successfully extinguished by this method.

Another method commonly employed in extinguishing gas-well fires involves the lowering of a large diameter pipe in a vertical position over the well, in such a way as to enclose the burning column of gas. The pipe serves to prevent admixture of air with the gas until it has passed through the pipe, the flame being confined to the gas above the upper end. The pipe is simply allowed to topple over, throwing the flame to one side of, and to a safe distance from, the well. Figure 223 illustrates a small portable extinguisher operating on this principle, that is used by the Empire Gas and Fuel Company in combating small gas fires. The hood which is lowered

over the casing head is in this case mounted on wheels and supports about 20 ft. of 14-in. pipe. When the device is in position over a burning well, a valve or damper in the upper end of the hood cuts off the supply of gas to the fire, directing it through

(*After C. P. Bowie, U. S. Bur. Mines, Bull.* 170.)
FIG. 223.—Portable gas-well fire extinguisher.

a side outlet connecting with a 10-in. pipe which carries the gas to a safe distance from the fire. The same principle has been applied with larger and more cumbersome apparatus in controlling large fires. In one case it was found possible to suspend a cableway over a gas-well fire from elevated ground on either side, on which

(*After C. P. Bowie, U. S. Bur. Mines, Bull.* 170.)
FIG. 224.—Placing a 36-in. smoke stack over a burning gas well.

a 36-in. smokestack riveted to a funnel-shaped hood was transported to a point over the fire and lowered over the casing head (see Fig. 224). When the flame had passed to the top of the stack, the ground and metal parts about the well were thoroughly

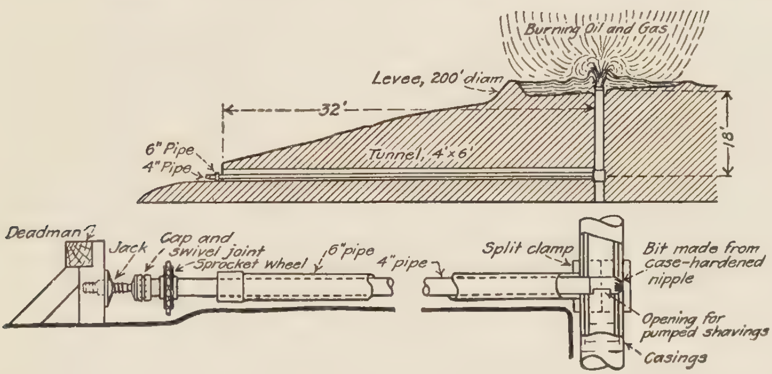
cooled with water, the top of the stack was drawn over at a considerable angle and the base quickly removed from the well, thus cutting off the supply of gas through the stack and extinguishing the fire.[1]

A method of successfully combating gas-well fires involving the use of explosives has been applied in several instances. A fire well in the Elk Hills field had defied efforts to extinguish it with steam and carbon tetrachloride, when the use of explosives was suggested. Wooden towers erected on two opposite sides of the well provided a means of stretching a cable a few feet from one side of the column of flame, which extended 200 ft. into the air above the casing head. A small carriage was rigged, suspended on two flanged pulleys traveling on the cable, and a second pull rope provided a means of moving the carriage along the cable. A charge of 150 lb. of blasting gelatin was suspended from the carriage and the latter moved along the cable until it reached a position near the column of flame. The explosive was then detonated electrically. Observers state that the flame was literally blown out by the force of the explosion, the upper part of the column being blown upward, the lower part downward and the central portion horizontally away from the position of the explosive. A number of boilers were fired and the steam, with about 100 bbl. of carbon tetrachloride, was brought to bear upon the base of the fire at the time of the explosion. This particular well ranks as one of the world's largest gas wells, the flow being in excess of 100,000,000 cu. ft. at the time of the fire. It was ignited by friction of the gas, carrying large quantities of shale and sand, upon the 6-in. flow line through which the gas was ejected from the well. Explosives have since been successfully used in a somewhat similar manner in extinguishing several oil and gas fires in the fields of southern California and in Texas and Oklahoma.

Oil-well Fires.—In the case of an oil-well fire, the flame is not usually confined to a well-defined column, as in the case of gas. Burning oil falls all about the well so that the source of the fire is more difficult of approach. The casing head and metal parts of the rig become heated so that they often reignite the oil after it has been extinguished, unless it can be kept under control for a sufficient time for surrounding objects to cool.

Many spectacular oil-well fires have been experienced in the American fields, and published accounts of them provide interesting reading and describe many ingenious methods used in extinguishing and controlling them. The methods employed necessarily vary with the size of the fire and the surrounding conditions. Steam is customarily employed, as described above, but in the case of certain large fires has been unsuccessful. In one instance, a 1,000-bbl. well became ignited, and, owing to lateral deflection of the stream of oil as a result of collapse of the casing head, a crater 50 ft. in diameter and 40 ft. deep was formed about the well. A large number of boilers were set up near the well and steam and water applied in the usual way. Though the fire was repeatedly extinguished, the heated walls of the crater reignited it as soon as the blanket of steam cleared. This fire was eventually extinguished by flooding the crater with mud, mixed in a large reservoir specially constructed near by. Steam formed from the mud extinguished the fire, and the mud plastered and cooled the walls of the crater.

In another case of a fire well producing 48,000 bbl. of oil daily, it was found impossible to extinguish the flame with 36 boilers.[1] A circular levee 3 ft. high and 200 ft. in diameter was constructed about the well to confine the burning oil, and a 328-ft. tunnel was driven to intersect the well casing at a depth of 18 ft. below the surface. The well contained three strings of casing, 10, 8 and 6 in. A split clamp was placed around the 10-in. casing and to this was attached a 6-in. pipe extending beyond the portal of the tunnel (see Fig. 225). Ar especially constructed bit made from a case-hardened nipple was screwed on the end of a line of 4-in. pipe extending through the 6-in. line and equipped at its outer end with a cap and sprocket wheel to which was attached a rotary chain drive. A screw jack set against a post served to force the bit against the pipe as the 4-in. line revolved. Rotating the 4-in. pipe and bit caused the latter to cut a hole through all three casings, care being taken to stop the bit in the center of the 6-in. casing. A hole previously cut in the bit was turned so that asbestos shavings pumped under pressure through the 4-in. pipe were forced down into the stream of ascending oil and accumulated about the bit, closing the small



(*After C. P. Bowie, U. S. Bur. Mines, Bull.* 170.)

FIG. 225.—Sketch of tunnel and arrangements for extinguishing a large oil-well fire.

spaces about it and cutting off the supply of oil to the surface. The tunneling method was also successfully used in extinguishing an oil-well fire in the Santa Fé Springs field of California that resisted all efforts to extinguish it by other methods for a period of 7 weeks.

The work of combating oil fires is hazardous and difficult. The temperatures to which workmen are exposed are extreme. Such work as adjusting steam lines and nozzles and making preliminary arrangements requires that the workmen approach as nearly as possible to the well. At such times they may be partially protected by sheet-metal or asbestos shields pushed ahead of them as they advance. It may be necessary to continually spray the workmen with water to prevent ignition of clothing.

Precautionary Measures.—The destruction wrought by oil- or gas-well fires, and the difficulty experienced in their control, justify the use of every possible means of preventing and combating them in the incipient stages. Forges for dressing tools should not be placed in the derrick. Boilers should be placed at a reasonable distance away from the well so that a sudden flow of gas or oil may not come into contact with the boiler fires. Place wire spark screens over the boiler stacks and keep all dry grass and other vegetation cleared from about the rig. Electric lights

should be used in preference to any form of lamp or torch. The Moon generator* offers a convenient means of generating enough current for lighting purposes, if current is not otherwise available. If the well is flowing gas or oil, it is safer to flood-light the rig from lights placed on poles outside of the derrick. Wiring in or on the derrick is a menace. Avoid frictional heat in bearings of moving parts of the rig by frequent lubrication. Static electricity generated by the band-wheel belt, by the brakes or other moving parts has often caused fires. All parts should be properly grounded, and belts should be provided with copper brushes attached to a grounded pipe. Two pieces of steel struck forcibly together may form a spark which will ignite gas; or rocks blown from the well by explosives or by gas flow, striking the metal crown blocks or rig irons, may start a fire. Smoking should be prohibited in and about the rig. If matches are necessary, only the "safety" variety should be permitted. Gas often flows for considerable distances in ravines and depressions screened from wind currents, and instances are on record where gas accidentally ignited at some distance from a well has "struck back" along the communicating channel of gas, firing the well.

While precautionary measures are commendable, preventive measures involving control of the gas and oil are of greater importance. Mudding to restrict escape of gas while drilling is in progress, and adequate valve control to cut off the supply of oil and gas in case of a fire, are the best preventives.

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* Manufactured by Moon Manufacturing Company, Chicago, Ill.

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CHAPTER XII

WELL RECORDS AND SURVEYS; INSPECTION OF FORMATION SAMPLES; MAPS, SECTIONS AND MODELS

Many millions of dollars are expended annually in the drilling of new oil and gas wells. The results secured from this great expenditure are measured not alone in oil and gas produced but also in information relative to subsurface conditions. So valuable is this information to the oil producer in the subsequent development and exploitation of his property that he is justified in spending considerable sums in assembling and recording it. Increasing emphasis is given to this work by the more progressive oil companies. Up-to-date executives realize that the more technical and exacting methods of the future will require more complete and accurate records than have those of the past.

A handicap that the engineer of today must contend with in seeking to apply new methods in the older fields is the lack of suitable records of the early drilling. One often finds that very inadequate records are available: no logs of the wells, no production records; perhaps little is known of the thickness and character of the reservoir rock, the depth of water-bearing horizons and other matters of great practical importance. Such information is often essential in the conduct of future development work, in diagnosing production troubles, in planning well repairs, in making appraisals, in the application of improved methods of recovery and other similar engineering problems.

Today, the modern core drill brings to the surface a representative sample of the formation penetrated, upon which lithologic tests may be made and the characteristics of the material determined. Instruments are available through the use of which the exact course of a well—that is, its direction and amount of deviation from the vertical—may be estimated. Methods for correlating formations from well to well have been developed, so that the inclination and strike of strata may be determined. Improved equipment and technic have provided the means of securing more detailed and accurate information of subsurface conditions.

With this superior knowledge has come the necessity for recording it in a manner that will serve not only our own immediate needs but also the requirements of the petroleum engineer of the next generation, who will look to us for the record of what we do and learn in the active fields of today. Most of the larger oil companies recognize this obligation and are employing engineers, geologists, chemists, physicists and paleontol-

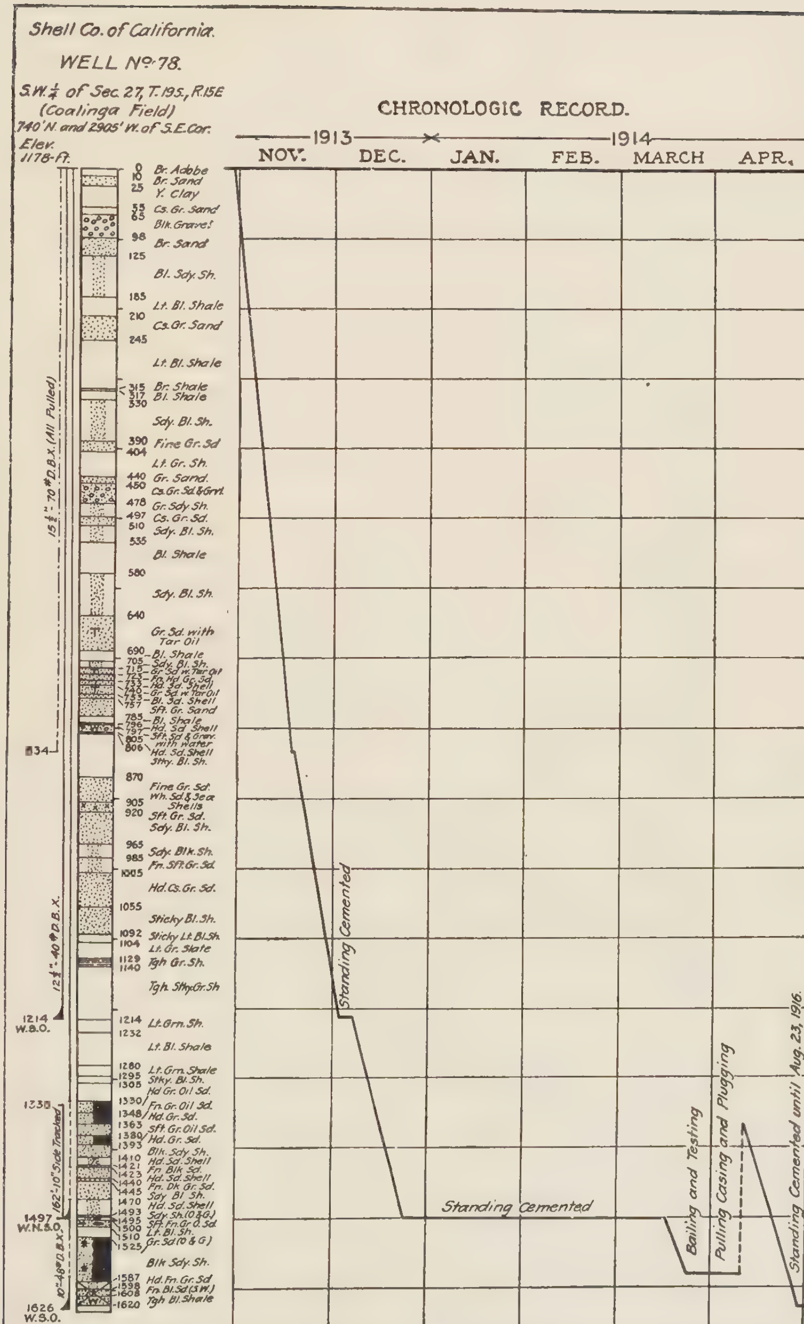


FIG. 226.—A typical graphic log with graphic chronological record.

ogists to gather data in the field, make the necessary tests and inspections in the laboratory and assemble the information in suitable records in the office.

WELL LOGS

Of the various records concerned with well data, none is more important than the log of the well. The log should give a complete

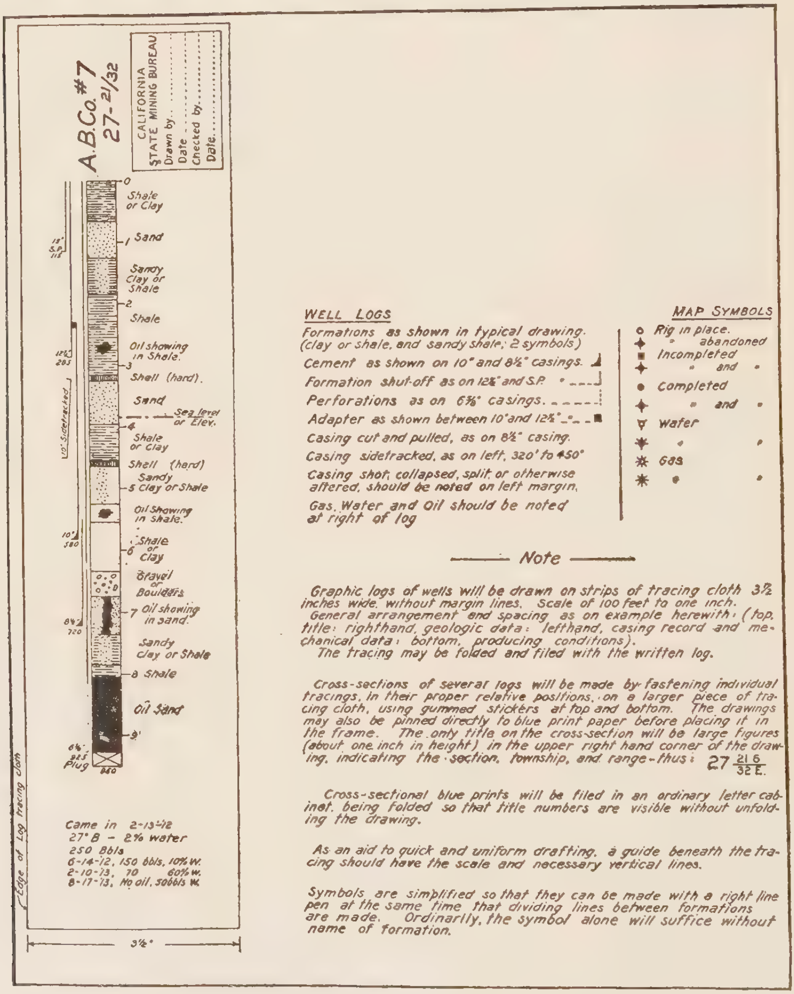


Fig. 227.—Conventional symbols for use on oil field maps and well logs adopted by California State Mining Bureau, Department of Petroleum and Gas.

history of the well from the time of its location until its abandonment. Every detail of the drilling procedure should be made a matter of record: the well equipment; the thickness, nature and depths of strata penetrated; depths at which oil, gas and water of special characteristics are encoun-

tered; depths at which casings are landed and water shut-offs made; water shut-off tests and names of witnesses; dates of starting and completion of drilling; names of drillers, tool dressers and others employed in the work; explosives used and depths at which used; pumping tests; initial production of oil, gas and water; and rating after 30 days' production. Repair work, redrilling jobs, alterations and important replacements of the well equipment, work involved in abandonment, etc., should be added to the original drilling record from time to time as such work is performed.

These data should be arranged in chronological sequence except for the stratigraphic record, which should be maintained in a separate table arranged in depth sequence. It is customary to classify these data under several different headings for convenience in reference. We may have one section devoted to the location of the well, another to the stratigraphic record; one to the chronological record of the original drilling, another to subsequent history; and still other sections will be concerned with the casing record, depths of oil and gas sands, water sands and water shut-off methods and tests. The log form* given on pages 452 and 453 is typical.

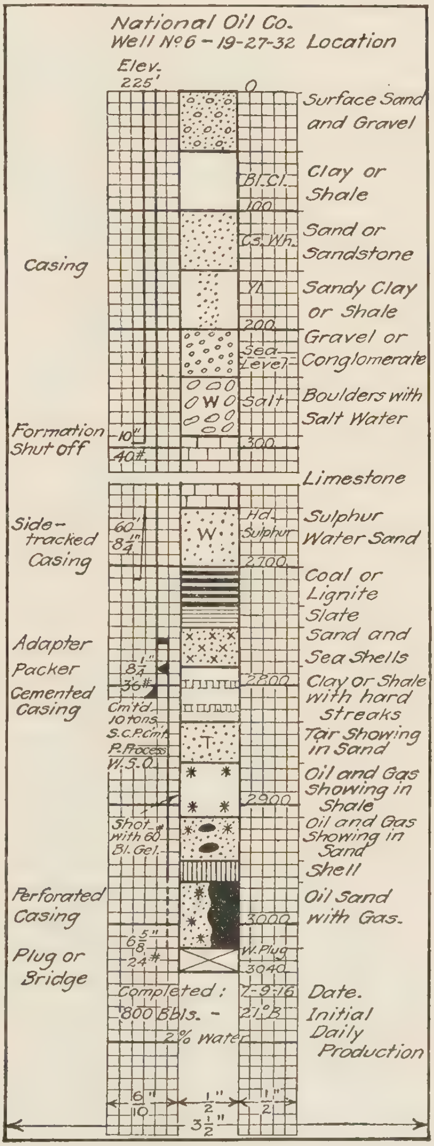


Fig. 228.—A proposed group of conventional well-log symbols.

Graphic Logs.—We may indicate much of these data with the aid of various conventional symbols on a graphic log, which is more desirable for certain purposes than the written historical record. Most operators will find it desirable to preserve the well record in both written and

* After A. W. Ambrose, U. S. Bur. Mines, *Bull.* 195.

SPECIMEN WELL-LOG RECORD

(Front Side.)

FIELD *Coalinga*

COMPANY *California Oilfields, Limited (Shell Co., of California)*

LOG OF WELL NO. 78

DESCRIPTION OF PROPERTY *(Quarter Section) S. W. ¼ of Sec. 27, 19/15*

LOCATION OF WELL *740′ N. and 2905′ W. of S. E. corner*

ELEVATION ABOVE SEA LEVEL *1178 Feet*

COMMENCED DRILLING *Oct. 29, 1913.* FINISHED DRILLING—*See History*

Depth from—	To—	Feet.	Formation.
0	10	10	Brown adobe.
10	25	15	Brown sand.
25	55	30	Yellow clay.
55	65	10	Coarse gray sand.
65	98	33	Black gravel.
98	125	27	Brown sand.
125	185	60	Blue sandy shale.
185	210	25	Light blue shale.
210	245	35	Coarse gray sand.
245	315	70	Light blue shale.
315	317	2	Brown shale.
317	330	13	Blue shale.
330	390	60	Sandy blue shale.
390	404	14	Fine gray sand.
404	440	36	Light green shale.
440	450	10	Gray sand.
450	478	28	Coarse gray sand and gravel.
478	497	19	Gray sandy shale.
497	510	13	Coarse gray sand.
510	535	25	Sandy blue shale.
535	580	45	Blue shale.
580	640	60	Sandy blue shale.
640	690	50	Gray sand, **shows tar oil.**
690	705	15	Blue shale.
705	715	10	Sandy blue shale.
715	723	8	Gray sand, **shows tar oil.**
723	733	10	Fine hard gray sand.
733	740	7	Hard sand shell.
740	753	13	Gray sand, **shows tar oil.**
753	757	4	Blue sand shell.
757	785	28	Soft gray sand.
785	796	11	Blue shale.
796	797	1	Hard sand shell.
797	805	9	Soft sand and gravel, **Water.** (Water stands at 600′.)
805	806	1	Hard sand shell.
806	870	64	Sticky blue shale.
870	905	35	Fine gray sand.
905	920	15	White sand and sea shells. (Put in 2 loads red mud at about 930′.)
920	965	45	Soft gray sand.
965	985	20	Sandy blue shale.
985	1,005	20	Sandy shale, black.
1,005	1,055	50	Fine soft gray sand.
1,055	1,092	37	Hard coarse gray sand.
1,092	1,104	12	Sticky black shale.
1,104	1,129	25	Sticky light blue shale.
1,129	1,140	11	Light gray slate.
1,140	1,214	74	Tough green shale. **(12½″ casing cemented at 1214′.)**
1,214	1,232	18	Tough, sticky green shale.
1,232	1,280	48	Light green shale.
1,280	1,295	15	Light blue shale.
1,295	1,305	10	Light gray shell.
1,305	1,330	25	Sticky blue shale.
1,330	1,348	18	**HARD GRAY OIL SAND, fair**
1,348	1,363	15	**FINE GRAY OIL SAND, good.**
1,363	1,380	17	Hard gray sand, no oil.
1,380	1,393	13	**SOFT GRAY OIL SAND.**
1,393	1,410	17	Hard gray sand, no oil.
1,410	1,421	11	Black sandy shale.
1,421	1,423	2	Hard sand shell.
1,423	1,440	17	Fine black sand.
1,440	1,445	5	Hard sand shell.
1,445	1,470	25	Fine dark gray sand.
1,470	1,493	23	Sandy blue shale. **(10″ casing cemented at 1626′.)**
1,493	1,495	2	Hard sand shell.
1,495	1,500	5	Very sandy shale, **shows oil and gas.**
1,500	1 510	10	Soft fine gray sand, **shows oil.**
1,510	1,525	15	Light blue shale.
1,525	1,587	62	Gray sand, **shows oil and gas.**
1,587	1,598	11	Black sandy shale.
1,598	1,608	10	Hard fine gray sand, no oil.
1 608	1,620	12	Fine black sand, shows **Sulphur Water.**
1,620	1,629	9	Tough black shale.

a Original, 8½ by 21½ inches in size.

SPECIMEN WELL-LOG RECORD *(Continued)*

(Reverse side.)

(Log Continued.)

HISTORY OF ORIGINAL DRILLING.

Casing froze at 1353'. Bailed to free the 10" casing and bailed dry. No record concerning water (12/15/13). Put in red mud, drilled ahead, finding 40'. Cavings in hole (12/16–18/13).

10" casing cemented at 1497' with 56 sacks cement dumped in (12/24/13). Cement 10' in casing, but bailed out 5'. Cement set to Mar. 16, 1914. Bailed hole dry, stood 6 hours and made no water. Drilled pocket to 1517', bailed hole dry, stood overnight and made 2 pails of water and a little oil. Then started to put in 8¼" casing. Drilled hole to 1620'; well showed evidence of sulphur water.

8¼" casing. Had in 1581' of 8¼" casing and then pulled two joints and bailed hole dry, stood 5 hours, and made 168' of water and no oil. Bailed hole dry and sand filled hole up to 1550'. Bailed at 1-hour intervals and well made 5 bailers (6⅝" by 40') each run of black water, "smelling strongly of sulphuretted hydrogen. There is also a little oil" (3/24/14).

Bailed, hole made 5 bailers per hour of water with a little tar oil. Made 10 bailers after standing 2 hours (3/25/14). Bailed hole, made 5 bailers per hour of black sulphur water with a little tar oil (3/26/14). Bailed; no change in quantity of water or oil (3/27–30/14).

Pulled so as to loosen 10" casing and cement it lower in order to shut off sulphur water (3/31/14).

10" casing. Got 10" vibration at 1425'. Filled hole from 1501' to 1497' with brick and cement. Put in 5 sacks cement and drove two wooden plugs into cement, top of plugs at 1490'. Dumped in 10 sacks cement and drove two wooden plugs, filling hole to 1462'.

Ripped 1425' to 1455' and filled hole to 1385' with 19 sacks cement, broken concrete, M. & F. plugs. Dumped in wheelbarrow load of gravel and ripped 10" casing at 1345' to 1370'. Put in 4 sacks cement, filling hole to 1365'.

Pulled 1335' (4/11/14), left 162'. 1335' to 1497' to be cased off. Drilled to 1395' and found tools following old hole. Filled to 1370' with bricks and 8" by 8" timbers, then drilled past casing to 1629'. Reamed to 1626'.

10" casing cemented at 1626' (4/29/14) with 73 sacks cement dumped in. Ran in and found cement 10' up in casing. Shut down for cement to set.

Idle until August 23, 1916.

HISTORY OF PLUGGING AND PERFORATING.

10" casing. Drilled pocket to 1630' (8/25/16). Bailed dry at 3-hour intervals. Made 3½ barrels of water per hour. Tested by bailing from Sept. 30, 1916, to Oct. 1, 1916. Made 2¼ barrels of water per hour.

Plugged to 1587' feet with 50 sacks cement, Sept. 2, 1916. Perforated by machine as follows: 1330–1410; 1423–1470; 1529–1580.

Bailed. Made 29 barrels of oil in 24 hours. Small show of water, Sept. 15, 1916. Tubed at 1480' with 3" tubing Sept. 30, 1916.

Production. About 40 b/d and no water. Gravity 25.3.

CASING RECORD.

15½ in. landed at *834* ft., cut at *(All Pulled)* ft., weighing *70* lbs. brand *DBX* *(11/17/13)*
12½ in. cemented at *1214* ft., cut at ft., weighing *40* lbs. brand *DBX* *(12/3/13)*
10 in. cemented at *1626* ft., cut at ft., weighing *48* lbs. brand *DBX* *(4/29/14)*

OIL AND GAS SANDS.

From *640* ft. to *690* ft.	From *1380* ft. to *1393* ft.
From *715* ft. to *723* ft.	From *1500* ft. to *1510* ft.
From *740* ft. to *753* ft.	From *1525* ft. to *1587* ft.

WATER SANDS.

From *797* ft. to *805* ft.	*Water stands at 600* ft.
From *1620* ft. to *1608* ft.	

METHOD OF SHUTTING OFF WATER.

12½ in. casing cemented at *1214* ft. with *31* sacks of *GG (12/3/13)* cement.
10 in. casing cemented at *1497* ft. with *56* sacks of *dumped in (12/24/13)* cement.
10 in. casing cemented at *1626* ft. with *73* sacks of *dumped in (4/29/14)* cement.
From -------- -------- -------- -------- --------

WATER TESTS.

(State how long cemented. Water level. Details of bailing and results.)

12½" casing. Practically no cement in casing. Cemented at 1214' (12/3/13). Set until 12/7. No record of any test.

10" casing cemented at 1497' with 56 sacks cement dumped in (12/24/13). Cement 10' in casing, but bailed out 5'. Let cement set to 3/16/14. Bailed hole dry, stood 6 hours and made no water. Drilled pocket to 1517', bailed hole dry, stood overnight and made 2 pails of water and a little oil.

10" casing cemented at 1626' with 73 sacks cement dumped in (4/29/14). Ran in and found cement 10' up in casing. Shut down for cement to set.

PERFORATIONS.

Machine From.	To.	Rows.	×	Holes per foot.	*See History.*
--------	--------	--------	---	--------	--------
--------	--------	--------	---	--------	--------
--------	--------	--------	---	--------	--------

Gravity of oil *25.3* Water cut *0*
Date well began prod. *Sept. 30, 1916.*
Remarks: (Special features not provided for above)

Initial rating of well *40 b/d*
Heaving plug (material).

At a depth of Feet
Drillers. —
Harper, Brandle, Wheat.

graphic form. The graphic record, plotted to vertical scale as illustrated in Fig. 226, is particularly valuable in that it conveys quite readily, by pictorial means, facts which can only with difficulty be made strikingly apparent in the ordinary form of written record. For example, it conveys a true impression of relative depths, thicknesses of strata encountered in the well and their sequence and indicates the manner in which the well is cased to better advantage than is possible in the written record. There are no conventional well-log symbols that are yet recognized as standard, but those suggested in Fig. 227 have been adopted by the State Mining Bureau of California and have found wide application in drilling records in that state. The author has compiled the somewhat more complete group of conventional symbols given in Fig. 228 from several sources.

In selecting symbols for use on well logs, considerable time and expense may be saved by using simple forms that can be readily applied. They should, however, be sufficiently distinctive so that no confusion in interpreting them will result. Predominating rocks, such as shale or sandstone, may be left blank. Rock colors may be indicated in connection with the conventional forms representing different types of rocks, by the use of the suitable abbreviations. The fluid content of the formation penetrated—either oil, gas or water—must also be indicated at the proper scale depths. Oil may be represented by solid black applied over the entire stratum in which it occurs, if present in quantity, or in irregular patches on the formation graph if only slight "shows" are in evidence. Water and gas are conveniently indicated by their initial letters placed at one side of the stratigraphic record. It is customary to indicate the depths to the top and bottom of all oil and gas sands, as well as important marker horizons and reference points, by the use of small figures placed at one side of the formation record.

The casing record forms an important part of the graphic log. This usually consists of a series of vertical lines about ⅛ in. apart, placed at one side of the formation graph, one line being drawn for each "string" of casing placed in the well. The landing depths should be indicated by terminating each vertical line at the proper depth with reference to the scale used on the formation graph. A short horizontal line at this point emphasizes it more definitely, and the depth and diameter of casing should be lettered along it. When a string of pipe has been cemented, a freehand fillet of sufficient weight to attract the attention may be applied in the angle formed by the horizontal and vertical lines (see Fig. 228). If tests show that water has been successfully excluded by the cement, the abbreviation W.S.O. (water shutoff) may be added, or W.N.S.O. if unsuccessful. Perforated casing or screen pipe can be indicated by dotted or dashed lines.

Brief notes descriptive of the drilling operations, the results obtained and interpretations of data should be freely used, lettering them neatly at the proper point opposite the formation graph. At the top of the graphic log should be lettered the well number, its location, elevation of the floor of the derrick and date of starting. At the bottom should appear the final depth, date of completion and the rating of the well, or its initial production of oil, gas and water. The gravity of the oil should also be given.

Graphic well logs may be conveniently constructed on strips of tracing cloth 3 in. wide and long enough to permit of plotting the entire record on a scale of 1 in. to 100 ft. This scale is large enough to show a 2- or 3-ft. stratum. Tracing cloth on which

is printed a 10- by 10-in. cross-section grid is convenient, permitting the log to be constructed without the aid of a scale. However, the coordinate lines obscure to some extent the conventional symbols used. By working on the reverse side of the cloth from that on which the coordinate lines are printed, and removing the latter with alcohol or chloroform when the drawing is completed, this difficulty can be overcome. Some draftsmen prefer to use plain tracing cloth, plotting the log over a specially prepared standard form ruled with horizontal lines $\frac{1}{10}$ in. apart, which may be slipped under the tracing cloth before the work is begun. Every 100-ft. interval should be indicated in this case for convenience in reference.

Blueprinted copies of the logs are quickly made from the tracings when desired. A more pleasing result is obtained by making brown-process prints from the tracings, using these in turn to make blue-line or positive blueprints; or, brown-process paper may also be used in making the positive prints, securing a black-line print closely resembling the original drawing. The black-line or blue-line print may be tinted, if desired, with the aid of water color or crayon, a process which greatly enhances the final appearance of the logs and gives opportunity for the use of distinctive conventional colors.

The data incorporated in the well logs must be collected for the most part by the drillers, though the average driller is poorly equipped for the work of identifying the mineralogical and lithological characteristics of the formations penetrated. The driller usually has at his command a limited vocabulary of colloquial rock names, often local names, which are based on the hardness, toughness and color of the material rather than upon any petrographic classification. However, he is usually able to distinguish such common materials as sand, sandstone, limestone, clay, shale and conglomerate, and when supplemented by descriptions of color and texture, for most purposes this is sufficient, if carefully and accurately done. The colors recorded are ordinarily those exhibited by the wet material as it comes from the well. For more accurate technical identification, samples of each formation, carefully labeled with the depth from which they come, should be preserved in bottles for the use of the geologist.

INSPECTION AND ANALYSIS OF FORMATION SAMPLES

In gathering data for the stratigraphic record, it is desirable that classification of the materials comprising the various strata penetrated by the well be made on the basis of suitable formation samples by one capable of properly identifying them lithologically and mineralogically. In the drilling of "wildcat" wells or wherever the securing of an accurate stratigraphc record for correlation purposes is important, the larger oil companies frequently take special precautions in securing representative samples of each stratum penetrated and employ geologists or engineers skilled in this class of work to classify the materials accurately. Such work may go far beyond the mere identification of the kind of rock composing the sample and may include identification of the fluids present within its pore spaces, determination of its porosity and permeability, the size distribution of its component grains, as well as microscopic inspection to determine its fossil and mineral content. While not widely practiced during the earlier period of oil field development in the American fields, work of this nature has recently found application and promises to become increasingly important in future. Many of the

problems of the oil producer that now seem difficult of solution will be easier of analysis when more complete and dependable stratigraphic information is made available.

The materials upon which the engineer or geologist conducts his tests may be pulverized formation samples segregated in the normal course of drilling, or they may be core samples taken with special coring devices used at appropriate times with this purpose in view. Pulverized formation samples, such as may be obtained from the circulating system of a rotary-drilled well, are generally too far disintegrated by the drill to provide an accurate sample for complete identification. Such samples are often contaminated with mud fluid or with fragments from overlying strata, and it is only with difficulty that one may visualize the appearance and characteristics of the material as it exists in place. So-called "bit samples," which consist of coarse fragments left clinging to the drilling bit when it is withdrawn to the surface, are more satisfactory, but it should be remembered that such specimens usually consist of harder, more resistant portions of the stratum from which they come and are therefore probably not entirely representative. By far the most satisfactory type of formation sample for inspection and test purposes is found in a core sample which, when properly taken by a suitable coring tool, is an actual sample of the formation as it exists in place in the bottom of the well. Such cores are cylindrical in form and are often from 2 to 4 in. or more in diameter, and anything from 1 or 2 to 10 or 15 ft. long. The character of the core depends upon the nature of the formation from which it is taken, the method of drilling and the type of core barrel used. Some rocks core much more satisfactorily than others, the harder and more thoroughly cemented rocks generally yielding the most perfect samples. Rotary core barrels generally produce a more complete and less disturbed formation sample than do the cable-tool core barrels now available. The most satisfactory core for identification and test purposes is that secured by the diamond drill. In hard rocks the diamond drill secures a dependable sample of practically 100 per cent of the formation penetrated, with little or no compaction or disintegration of the rock structure. Even a portion of the fluids stored within the rock pores may be brought to the surface with the core.

Field Inspection and Preservation of Core Samples

When a core sample is brought to the surface, on removal of drilling equipment from the well, it should be immediately extracted from the core barrel and given preliminary inspection and measurement. This work should be done by an individual capable of interpreting the conditions indicated and of identifying the different components of the sample and its contained fluids. Certain information may be gathered from the appearance of the core immediately after it has been removed from the core barrel, that cannot be so readily determined at a later time.

The core should be placed in suitable trays or boxes as removed from the core barrel, taking care that the various sections are assembled in the exact sequence in

which they were cut by the drill. The total length of core obtained is then determined by careful measurement and compared with the footage advanced by the drill. The total length of core produced will usually be less than the measured advance of the drill, that is, some of the core will be "lost" by breakage, compaction, abrasion or washing. The percentage of core secured, a figure determined by dividing the actual length of core by the footage drilled, may vary from as low as 50 per cent in soft formations to 100 per cent in hard rocks, depending upon the type of coring device used and the skill of the driller in manipulating the equipment. Inspection of the core will often disclose where portions of the formation penetrated have been destroyed or are missing in the core as assembled in the storage trays. In such cases, wooden blocks cut to proper length are inserted in the core, in place of the missing section, so that the total length with the "spacers," as displayed in the trays, will be equivalent to the depth advanced by the drill. The top and bottom of each core section or tray are carefully labeled with the upper and lower limits of depth in the well from which the material has been taken.

When the core has been assembled in the supporting trays, with such "spacer blocks" as may be necessary to allow for lost portions, measurements are made to determine the depth below the derrick floor (or other datum plane) to the top and bottom of each component stratum that can be identified by careful visual inspection of the core. The position and character of each "parting" or "break" are carefully noted. Any peculiarities that may be observed at any point, such as the character of the bedding, the nature of the rock crevices, joint planes, fossils and general texture of the material, are also made a matter of record and all such observations are carefully correlated with the depth measurements.

The character of the fluid content of each individual stratum will also be noted and recorded, particularly oil and gas. An oil-saturated core will generally "bleed," that is, some of the oil will be expelled from the pore spaces of the material, the surface of the core becoming wet with oil. This is caused primarily by expansion of gas which is invariably associated with the oil in the reservoir rock. Often, if much gas is present, a large part of the oil will be quickly expelled from the core, and oil accumulating on the surface will appear to effervesce. The observer should note the sections of the core from which important quantities of oil are lost by "bleeding," in order that appropriate corrections may be made in the analytical data later to be assembled from the results of the laboratory tests. Water-saturated strata may also be readily identified and distinguished from those which yield gas or oil. The presence of gas in a stratum, in the absence of oil, may usually be identified by its odor if the core is examined promptly following its removal from the core barrel.

The presence of oil in sands that have become water flooded, or in which the oil is present only in minute quantities, will at times be a matter of uncertainty. In such cases, a small sample, appropriately selected from the core, may be pulverized and immersed in chloroform, ether, carbon bisulphide or carbon tetrachloride, these reagents becoming discolored to some shade of brown by solution of even small quantities of the dark-colored oil. Some oils are too light in color to yield a satisfactory test by these reagents. In this case the acetone test may be used to disclose their presence. This test consists in placing a little of the pulverized sample in a test tube or other glass receptacle with a little water. A few drops of acetone are added when, if oil is present, the water becomes milky in appearance.

Identification of the types of rock comprising the different sections of the core can generally be made by casual inspection. Sands, sandstones, shales, conglomerates, clays, slates and limestones—the common rock types in most well logs—are sufficiently dissimilar to permit of identification even by the novice. An acid test is sometimes necessary to identify limestone or calcareous sands, the characteristic effervescence in cold hydrochloric acid being unmistakable.

It will be important in the preliminary field inspection of the core to assemble as complete a log of the formations penetrated as may be possible, recording the depth measurements that have been made to top and bottom of each component stratum, together with its classification, that is, the kind of material of which it is composed. The field notes assembled in conjunction with the log should describe the material as accurately as may be possible by casual inspection and such simple tests as may be conveniently made at the well. For example, a sandstone will be described as to color while wet, indicating also its texture—that is, whether fine, coarse or medium grained, angular or well rounded—and the extent to which cementation of the component grains has progressed (that is, unconsolidated, semiconsolidated or well indurated). The nature of the cementing material may also be determined in many cases by field inspection with the pocket lens. The more prominent mineral constituents of a sand or sandstone may also be noted, it being usually possible for one familiar with mineralogy and crystallography, on inspection with the pocket lens, to identify quartz, biotite, muscovite, hornblende, augite, calcite, olivine, the various feldspars and other common rock-forming minerals and roughly to estimate the preponderance of one or another in the association of grains composing the sand or sandstone. Any fossils that may be noted should also be identified as to type and made a matter of record. Such details may later be useful in correlations of strata in the logs of different wells and will assist in identifying any part of the core in case it should later be misplaced or disarranged.

Preservation of Core Samples.—If core samples are to be used as a means of estimating the oil content of reservoir sands, it will be important to adopt some method of handling that will result in minimum loss of the rock fluids or exchange of fluids as between one stratum and another. Evaporation and bleeding of oil from the core as a result of gas expansion will quickly result in loss of an appreciable percentage of the oil present unless the core is promptly protected against such losses as soon as possible after removal from the core barrel.

Protection of oil-sand samples at this stage should contemplate transportation to the laboratory where tests are to be subsequently made and prevention of oil losses during a period of from several days to a week or more during transit, though the saturation tests should be made as early as is conveniently possible. The entire core may be shipped to the laboratory with the purpose of affording an opportunity for more technical inspection and selection of test samples than is possible in the field, or representative samples of the core may be selected in the field and only these sent to the laboratory.

Instead of shipping the entire core to the laboratory for analysis, it is a better plan to select such samples as will be needed for analysis in the field and ship only these to the laboratory. The routine of analysis requires only a few ounces of the material, and samples of small size can be much more economically transported and protected against oil losses in transit. Samples taken in this way are conveniently placed in round, seamless tin "ointment boxes," such as may be purchased from many druggists or laboratory supply dealers. The covers of these containers are readily sealed against leakage by a strip of friction tape. The samples for laboratory analysis should be selected promptly after the core is assembled, after removal from the core barrel. If a small portable balance capable of weighing to about 10 mg. can be taken into the field and set up on an improvised work bench, each sample can be weighed as it is placed in its container. On making the saturation test at a later date in the laboratory, the sample can be again weighed and the loss of weight in transit determined. This loss in weight represents oil loss due to bleeding and evaporation and the volume so lost can be readily calculated if the density of the oil is known; the amount lost is then added to that found in the sample on testing. When this plan is followed, no special precautions need be taken against loss of oil during transit to the laboratory.

The weight of each sample, as determined in the field, should be marked on the container or recorded on a numbered list sent with the samples to the laboratory, care being taken to correlate properly the list with reference numbers marked on the samples or their containers.

In selecting samples of the core for analysis, whether in the field or in the laboratory, a sufficient number should be taken to provide at least one analysis for each distinct stratum penetrated; and if a particular bed seems to vary in texture, two or more samples should be taken at different depths. It is important in this connection to keep in mind the ultimate purpose of the analytical work, which is to provide data on the saturation, porosity and grain size of the formations represented in the samples. Care should be taken that the samples selected are as nearly as possible representative of the strata from which they are taken. In cases where the beds are thin and alternations of sandstone and shale are frequent, the selection of a reasonable number of samples that will be representative of a section of core may present no little difficulty, but careful inspection of the material will generally permit of reasonably representative samples being chosen.

The samples selected for analysis may conveniently be disks about 1 in. thick, broken across the full cross section of the core at right angles to the axis; or, they may be sections of the core several inches long, obtained by splitting along its axis. The latter type of sample, exposing a fractured surface across the bedding planes, is generally preferable for inspection purposes, but for routine analysis, to determine porosity and saturation, the disk sample is equally satisfactory and the core is more readily broken in this form. Loosely consolidated material may be broken in the fingers. If the material is hard and resistant, disk samples may readily be broken with a hammer and cold chisel. Splitting cores longitudinally is less easily accomplished. A convenient device for this purpose, suitable for laboratory use, is manufactured by the E. J. Longyear Company, Minneapolis, Minn.

Cores from drilling wells are costly and often represent a considerable investment. They are not merely of temporary interest but will be of permanent value for reference purposes and may conceivably serve a variety of functions. Perhaps many years after they are taken, they will be a matter of interest in estimating recovery possibilities, in controlling clean-out operations, placing packers, cement shut-offs, locating shots and in other operations incidental to oil-well operation and repair. Since they are of permanent value, they should be carefully preserved by providing a place of storage where they may be systematically arranged for such inspection as they will occasionally receive. It will seldom be necessary to take precautions against evaporation losses from stored cores, since the results of the analytical inspection, made soon after the cores are taken, will presumably always be available as a record of the original fluid content. The trays or boxes containing stored cores should be labeled on the ends exposed in the rack, with the well number and depth to top and bottom. Where much coring is done and the cores from many wells must be stored, the bulk and weight of material to be cared for are large. Some operators transport all formation samples to a centralized point of storage; others erect at each well, a small shed in which the cores from that well are permanently housed.

LABORATORY INSPECTION AND ANALYSIS OF CORE SAMPLES

If sampling has not been done in the field as recommended in the foregoing section, on reaching the laboratory each section of core is carefully unwrapped and samples are selected for analysis. Substantially the same procedure as that outlined for selecting samples in the field is followed. The samples so chosen are immediately weighed on a chemical balance and placed in covered sample boxes or weighing dishes until such time as they can be subjected to further treatment for elimination of the contained fluids, the weights being carefully recorded on the container or on a list correlated with the numbered containers.

Extraction, Identification and Measurement of Fluid Content of Core Samples.—The nature of the tests to be applied in determining the fluids present in a core sample, and their amount, will depend upon the amount of fluid (oil or water or both) that may be present, and whether merely a qualitative test or a quantitative measure of the amount present is required. In some cases, the sample will be well saturated and there will be no uncertainty concerning the presence of oil. In other cases, the sample may contain only small amounts of oil and delicate tests must be applied to determine its presence.

Qualitative identification of petroleum residues in such materials is comparatively simple. The solution-test method is the one generally employed, the common solvents for petroleum—such as chloroform, ether, carbon bisulphide or carbon tetrachloride—being discolored in a characteristic way by contact with petroleum, even though only small traces are present in the material under examination. These tests, together with the acetone test described on page 457, are commonly used in the laboratory, as in the field, for determining the presence or absence of petroleum in core samples. If considerable oil is present in the sample, a few minutes' agitation of a small portion of the material in a test tube or white porcelain dish may be sufficient to bring about the color change in the solvent; but, if only a small quantity is present, a more delicate method must be employed. The following routine may be followed in extracting small quantities of petroleum from formation samples.

The sample is pulverized in a mortar and after drying for a time at normal atmospheric temperature, to permit of escape of moisture, 1 teaspoonful of the powdered material is placed in a clean 4-oz. bottle with 3 teaspoonfuls of pure chloroform or other solvent. The bottle is securely corked and then shaken for about 1 hr., taking care that the liquid does not touch the cork which may contain enough soluble material to discolor the solvent. A clean glass funnel holding a dry folded filter paper is placed in the neck of a second 4-oz. bottle and the contents of the first bottle poured on the filter paper, the filtrate accumulating in the second bottle being thus freed from sand or other visible solid particles. If the filtrate contains petroleum, it will be discolored to some shade of amber or yellowish brown, the intensity of color depending upon the quantity of oil present in the sample. The filtrate is next poured into an evaporating dish and allowed to evaporate in a warm place near an open window, taking care that no dirt, dust or other foreign substance collects in the dish. If the original sample contained petroleum, there will be left on the dish, after the solvent has evaporated, a yellowish or amber-colored stain, the darkness or intensity of which will depend upon the quantity of oil in the sample. In connection with this test, the analyst should remember that it is unsafe to evaporate chloroform, carbon tetrachloride or ether in other than a well-ventilated room. Neither is it safe to apply direct-heating methods in hastening evaporation, for the vapors coming into contact with a free flame or a heated metal surface will produce obnoxious gases such as chlorine, phosgene or other irritating or poisonous compounds.

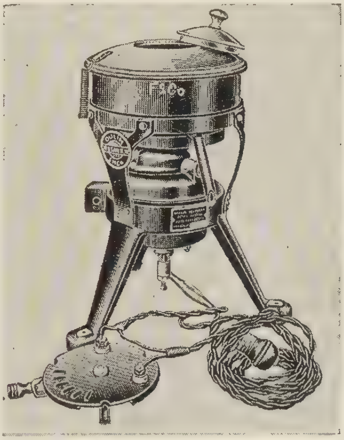
Soxhlet's extraction apparatus lends itself well to determination of oil in formation samples, though the apparatus is somewhat more expensive and complex than that required in the simple test just described. Larger quantities of solvent are also required and the process of evaporation to obtain the oil-stained residue occupies a more extended period of time. Figure 229 illustrates one variation of the Soxhlet apparatus. The flask contains the solvent, which is heated by an electric hot plate. A tube penetrating the ground-glass stopper of the flask communicates with a larger glass tube which supports a porous alundum thimble in which the material to be treated is placed.* A siphon tube serves to periodically drain the solvent back into

* For the extraction of oil from formation samples the author prefers a filter-paper thimble manufactured by the Whatman Paper Company to the alundum thimble. These paper thimbles are inexpensive and a new one is used for each test.

the flask the lower part of the tube being closed. A vertical reflex condenser communicates through a ground-glass stopper supported in the upper end of the tube with the interior thereof. In operation, vapor from the heated solvent passes up through the vapor tube and thence into the water-cooled condenser. Here the vapor is condensed, dropping back through the lower end of the condenser on the sample under treatment in the porous thimble. The condensed solvent dissolves the oil in the sample and slowly seeps with the dissolved oil through the pores of the thimble, accumulating in the lower part of the containing glass tube until it reaches the overflow point of the siphon tube, when all of the accumulated liquid is siphoned back into the flask. The process continues, pure distilled and condensed solvent falling continually on the sample until it is completely leached, the solvent containing the solute

(Courtesy of Fisher Scientific Co.)

FIG. 229.—Soxhlet extraction apparatus.



(Courtesy of Fisher Scientific Co.)

FIG. 230.—Dulin "Rotarex," useful in extracting oil from formation samples.

being periodically siphoned into the lower flask, which thus gradually accumulates all of the oil originally present in the sample. When the extraction is complete, the solvent may be evaporated in a porcelain evaporating dish, or distilled off, leaving the oil as residue.

Another laboratory device that is useful in extraction of oil from unconsolidated sands and small fragments of sandstone is the Dulin Rotarex illustrated in Fig. 230. This machine comprises a small metal bowl, mounted on a vertical, motor-driven spindle which may be revolved at high speed. The sand or sandstone fragments, from which oil or other bituminous matter is to be extracted, is placed in the bowl with a filter-paper pad placed between the cover of the bowl and the sand. While the bowl is rapidly rotating, an oil solvent, such as petroleum ether, carbon bisulphide or carbon tetrachloride, is poured into the bowl from which it flows through a hole in the spindle near the bottom of the bowl, thence up through the sample and out through the filter pad into the outer stationary housing from which it flows through a spout into a receiving vessel. A few minutes' treatment of a sample in this machine

will serve to remove all traces of oil from the sample. Owing to the high centrifugal force developed, the sample is left practically dry, but moderate heating after removal from the bowl of the Rotarex will be necessary to completely expel the solvent.

Identification of Hydrocarbon Oils as to Type.—The analyst will often wish to determine the character of the oil that he has extracted from the formation sample, as described in the foregoing section. While the expressions "paraffin base" and "asphaltic base" have no very definite meaning from the physical and chemical points of view, they have general significance in indicating the predominating constituents of an oil and serve in a general way to enable one to predict the character of the products that might be obtained from them. Greater value is usually attached to the paraffin oils than to the asphaltic oils, but this is not necessarily warranted in all circumstances.

If the oil is of paraffin base, continuation of the evaporation of the oil residue provided by the foregoing extraction test, to the point of dryness, will leave a plastic, waxy substance, generally yellow or light brown in color, which is impure paraffin. Such oils consist chiefly of hydrocarbons of the paraffin series (C_nH_{2n+2}), and are fully saturated—that is, they are incapable of combining with more hydrogen. Asphaltic-base oils yield a hard, lustrous, black residue on evaporation to dryness. They contain the naphthenes (C_nH_{2n}), benzenes (C_nH_{2n-6}) and other aromatic hydrocarbons. All of these are relatively unsaturated. Some oils of mixed base contain both the paraffin and asphaltic compounds in about equal proportions, in which case the presence of the former will be to some extent masked by the dark color and stiff consistency of the latter. The terms "paraffin base" and "asphaltic base" are thus seen to be somewhat indefinite, the name of the predominating series of hydrocarbons being applied. The chief difference between the two types is to be found in the heavier constituents.

Interesting differences may also be noted in the manner in which the different hydrocarbons react with the stronger acids. The paraffin hydrocarbons are not acted upon by concentrated fuming sulphuric acid, are not nitrated by nitric acid and are extremely resistant to all chemical reactions. The naphthenes are also resistant to acids, but the aromatic or benzene hydrocarbons are acted upon by nitric acid, forming nitrogenous products, while the olefin hydrocarbons are acted upon by concentrated sulphuric acid.

Determination of "Percentage Saturation" of Oil Sands.—If qualitative inspection of the sample indicates that oil is present, it will perhaps be necessary to determine how much oil is present. The oil content may be expressed as a percentage of the weight of the sample or as a percentage of the volume of its pore space. Generally, the latter method is preferred, the resulting figure being called the "percentage saturation."

In determining quantitatively the amount of oil present, a portion of the original sample is selected, weighing perhaps 10 g. or thereabouts. The weight is determined by accurately weighing on an analytical balance, and the sample is then placed in a porcelain crucible and heated over a Bunsen burner until all contained fluids are evaporated and any carbon residue which may be formed is burned out. After cooling, the sample so treated is again carefully weighed and the loss of weight during the heating process is computed. This represents the weight of the total liquid content of the sample, that is, oil plus water, if the latter is present in the sample. In the event that carbonates or other minerals are present in the sample, which would suffer serious loss by heating in the manner suggested, it may be pulverized and placed in a constant-temperature electric oven maintained at a temperature below that at which decomposition of the mineral occurs, until all water and oil vapors are driven off. Generally, however, oil sands are composed largely of quartz, feldspars and other resistant minerals that may be heated to dull redness for a considerable time without

serious decomposition loss. If the sample has been selected and weighed in the field, the loss in weight during transit from the field to the laboratory must be added to that which is lost in the process of heating. The loss during transit of the portion of the original sample used for heat treatment in the laboratory is computed by proportion of weights. The total fluid content, by weight, per gram of the original sample is then computed.

In the event that both water and oil are present in the sample, the amount of water must be determined separately and subtracted from the total ignition loss as determined above, the difference representing the amount of oil present. The amount of water in a portion of the sample can be readily determined by distilling in the presence of an immiscible hydrocarbon oil solvent, such as gasoline, condensing the water and gasoline vapors, when a complete separation of the water occurs. For this purpose, the form of distilling and condensing apparatus recommended by the U. S. Bureau of Mines and by the American Society for Testing Materials* for determination of water in oil-water mixtures is used. The apparatus is illustrated in Vol. II of this work.

In determining water in a core sample by this method, a portion of the core weighing about 10 g. is selected, coarsely crushed in an agate or porcelain mortar and the fragments carefully transferred to the distilling flask of the apparatus. The weight of material placed in the flask must be accurately determined. About 50 cc. of a suitable oil solvent† is then added, the corks, condenser and measuring trap are adjusted and heat gradually applied, preferably with the aid of an electric heater in which the resistance-wire heating element is well protected against contact with vapors escaping from the condenser. As the vapors are evolved from the distilling flask into the reflux condenser, they condense and drain downward into the calibrated receiving trap. The water component accumulates in the conical tip of the trap, and, when water is no longer evolved from the flask on continued heating, the total volume of water in the sample may be directly determined by comparison with the trap graduations. The equivalent weight of water present, per gram of the original core sample, is then computed. On subtracting this amount from the total fluid content per gram, the oil content per gram is determined.

Having determined the proportions of oil and water by weight in the fluid content of the sample, the specific gravity of the fluid mixture may be computed if the specific gravity of the oil and water is known. The densities of the component fluids may, as a rule, be readily determined by tests on samples from near-by producing wells. Knowing the specific gravities of the oil, the water and the oil-water mixture, and the total weights of oil, water and total fluid per gram of sample, we may next compute the volume of fluid (water plus oil) in 1 g. of the original sample. Comparing these volumes with the total volume of the pore space in 1 g. of sample, as determined by a later test, we arrive at the "percentage oil saturation" and "percentage water saturation."

Determination of Porosity of Core Samples

The porosity of an oil reservoir rock is one of its most important lithologic properties. On this factor depends the storage capacity of the reservoir for oil and gas. The rate of oil production under a given reservoir pressure will also depend upon this property. A knowledge of porosity will therefore provide a useful basis for estimates of residual oil content, of pressure conditions necessary to cause move-

* See A. S. T. M. test D-95.

† A naphtha fraction having a boiling point ranging from about 90 to 210°C. is often used for this purpose; or a mixture of 80 per cent xylol with 20 per cent benzine will be found suitable.

ment of fluids and of potential rates of production. A useful distinction is made between "total porosity" and "effective porosity" or "available porosity," the latter term being applied to the communicating pore space from and through which drainage of fluid may occur to an exterior surface.

The percentage porosity of a sandstone may be determined by either of several methods. In the absorption method the porosity is computed by determining the quantity of a liquid or gas absorbed by a specimen of measured volume. When a liquid is used, the loss in volume of the liquid may be directly measured, while in the case of gas, the volume absorbed may be computed if the loss in pressure is noted. Another method involves comparison of the apparent specific gravity of a fragment of a sandstone specimen with the true specific gravity of the mineral grains composing it. Still a third method, and the one that is most used for accurate determination of porosity of oil and gas sands, is one which involves comparison of the volume of a specimen with the sum of the volumes of its component grains. In this method, the volume of the specimen, minus the volume of its grains, is equal to the volume of the pore space; and the pore-space volume, divided by the volume of the specimen, gives the percentage pore space.

The Melcher Method.—Melcher has described a method, based on the percentage volume principle, that has found extensive use in determining the porosity of oil and gas sands.[10] As just explained, it provides first for accurate determination of the volume of a small sample of sandstone, followed by measurement of the volume of its component grains. A small specimen of the rock to be tested, about the size of the end joint of one's thumb, from which all fluids have been removed, is selected for the test; and after thoroughly cleaning the outside surface of loose particles, it is broken into two approximately equal parts, one to be used in determining the volume of the grains, and the other for determination of the volume of the grains plus that of the pore space. The sample used in determining ignition loss, as described in an earlier section, may be conveniently used for the porosity test. Samples cleaned of oil by leaching in the Sohlet extraction apparatus or in the Dulin Rotarex, as described on page 461, may also be used. In the latter case, the residual solvent left in the sample may be evaporated by gentle heating.

Determination of Volume of the Grains Plus Pore Space.—One of the two parts of the specimen is carefully weighed on an accurate balance. The specimen is then dipped in molten paraffin, first one half and then the other, holding it with the fingers. The paraffin should be heated in a pan until it is thoroughly fluid, but to no higher temperature than is necessary to accomplish this. The rock fragment should be held in the molten paraffin only 1 or 2 sec., or even a shorter time if the material is very porous. The paraffin should not enter the pores of the specimen, as will be indicated by the evolution of gas bubbles. When the coating of paraffin is cool and hard, the fragment is again weighed and, by comparison with its weight as previously determined, the weight of the paraffin left on the surface of the fragment is computed.

The weight of the paraffin-coated fragment in water is next determined. For this purpose, the fragment is suspended from one end of the beam of a chemical balance on a very slender platinum wire (No. 30, B & S gage) or, if this is not available, by a strand of silk thread. The water in which the specimen is immersed should be distilled water, previously boiled to expel air, and, after cooling, placed under the beam of the balance, in a small beaker. During the weighing process, the temperature of the water should be accurately known. The paraffin-dipped sample is then removed from its support, thoroughly dried with a soft absorbent cloth and again weighed in air to make certain that no water was absorbed during the immersion period. If the weight is appreciably increased, a correction must be made to the weight of water displaced during the previous weighing, equal in amount to the difference between the weights of the paraffin-coated sample before and after immersion in the water bath.

In weighing the paraffin-coated sample in water, due allowance must also be made for the weight of the suspension wire and its loss of weight due to partial submersion. Subtracting the weight of the paraffin-coated fragment in water from its weight in air, we compute the loss of weight in water. From a previous determination of the density of paraffin (often about 0.906), and knowing the weight of the paraffin coating on the sample we compute the volume of the paraffin used. Subtracting this from the computed volume of the paraffin-coated fragment, we arrive at the net volume of the fragment.

Determination of Volume of the Grains.—The second portion of the original sample is next carefully weighed and then crushed in a smooth-surfaced mortar into its component grains. Inspection with the binocular microscope, from time to time, will determine when crushing has progressed to a point such that the grains are completely separated from each other. The sample is then again weighed and thoroughly dried in an oven or over a hot plate. The crushed material is then allowed to cool in a desiccator, again weighed, and exposed to the atmosphere for a time to take up moisture. When a constant weight is reached, the exact weight is noted and the amount of hygroscopic water that has been taken up by the sample is computed.

The crushed material is, with the aid of a sheet of glazed paper, transferred to a pycnometer of suitable size which has been previously weighed, first while empty, and then while filled with boiled, distilled water of known temperature. The remaining space within the pycnometer, after adding the crushed sample, is then filled about two-thirds full with boiled, distilled water, vacuum being applied with the aid of a vacuum pump or aspirator to remove all bubbles of gas that may be occluded within the crushed material, meanwhile agitating the pycnometer and its contained water and crushed sample. Boiling the sample in the pycnometer is also helpful in expelling air. Small residues of petroleum in the sample will cause air bubbles to adhere tenaciously to the crushed sample in the pycnometer, but thorough preliminary heating of the sample in a porcelain crucible over a Bunsen burner will remove all traces of oil so that it may be readily wet with water. A convenient arrangement of apparatus which permits of adding the water to the crushed sample in the pycnometer while it is under vacuum is illustrated in Fig. 231.

When all air has been removed from the crushed material, the remaining space within the pycnometer is filled with distilled water and the bottle with its contents placed in a water bath maintained at constant temperature until the whole is brought to a uniform temperature approximating that at which the subsequent weighing is to be performed. A constant-temperature, thermostatically controlled water bath is best adapted to this purpose, but, if not available, no great inaccuracy will result through the use in its stead of a beaker of water maintained at approximately constant temperature. The pycnometer is removed from the water bath after constant temperature has been attained, thoroughly dried on the outside and accurately weighed. From the weights previously determined, we may calculate, first, the weight of the water displaced by the sand grains, and, then, from its known density at the test temperature, the volume of water so displaced. This latter is the volume of the dry sample in the pycnometer.

By reference to the weights obtained for the paraffin-coated fragment, we may now calculate the volume of rock in place for a unit weight of rock fragment. Computing the volume of the grains for the same weight of rock fragment from the results obtained as outlined in the preceding paragraph, we next subtract the two volumes to find the total pore space per unit of weight of the original sample. This volume, divided by the volume of the rock in place, gives the percentage of total pore space.

Other methods and devices suitable for determining porosity of formation samples, described in the literature, include the Athy mercury-immersion method, the hydrogen porosimeter and the vacuum porosimeter. In the Athy method the "bulk density"

of the specimen is compared with the "absolute density" of its mineral grains, the bulk density being computed by determining the loss in weight of the specimen when immersed in mercury. The method is similar to that of Melcher, except in the means adopted for determining the bulk density of the specimen.

The hydrogen porosimeter, described by Coberly and Stevens,[2] is a convenient device in making rapid determinations of effective porosity. The basis for estimation of porosity by this method is the loss of pressure of a standard volume of hydrogen gas under pressure, when permitted to expand into and fill the voids in a chamber containing a rock specimen of known volume. The volume of the specimen is determined by mercury immersion.

The vacuum porosimeter and permeability apparatus designed by Tickell affords a means of determining the porosity of a specimen of known volume, enclosed in a

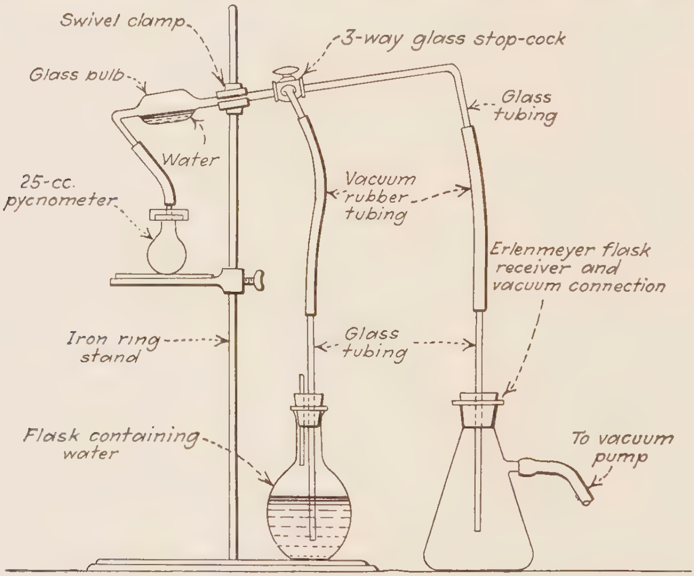


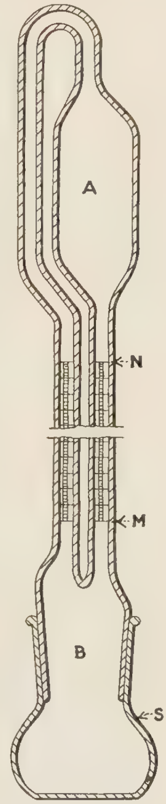
FIG. 231.—Apparatus for exhausting air from the pycnometer containing the crushed formation sample in determining porosity by the Melcher method.

chamber of standard volume, by recording the increase in volume of air within the chamber and the voids of the specimen when expanded to a certain degree of vacuum.[20]

Determination of Rock Porosity with the Aid of Acetylene Tetrachloride.—W. L. Russell has described a method for determining the porosity of rock specimens based on the same principle as that of Melcher, except that a special type of pycnometer is employed and acetylene tetrachloride is used as an immersion fluid instead of water.[16] This fluid readily enters and completely fills the pores of a sand or fragment of sandstone so that the process of dipping in paraffin becomes unnecessary. The method is said to be only slightly less accurate and yet is considerably more rapid than that proposed by Melcher. The necessary equipment and apparatus for determining porosity by this method can readily be carried into the field.

The special form of pycnometer employed is illustrated in Fig. 232. It consists of two graduated tubes which are enlarged at one end to form reservoir A, while at the other end they are connected by reservoir B. The glass tube forming the latter is ground on its exterior surface and is provided with ground-glass stopper S. The apparatus is so constructed that when the stopper is in place, as shown in the sketch,

the volume below the zero point M, on the graduated tubes, is equivalent to that above the uppermost graduation N. Holding the pycnometer with the reservoir B uppermost, and with the stopper S removed, the tubes are filled with acetylene tetrachloride up to N. Meanwhile a fragment of the specimen to be tested has been immersed in acetylene tetrachloride in a separate container until air bubbles have ceased to issue from it. The specimen is then removed from the fluid, the liquid adhering to its outer surface is wiped off and it is then placed in reservoir B, stopper S being adjusted, with the ground surfaces greased to prevent leakage. The pycnometer is then inverted to the position shown in Fig. 232 and the increase in fluid volume noted by reference to the graduated scale on the glass tubes. This is the volume of the specimen fragment.



(After W. L. Russell in Bull., Am. Assoc. Petroleum Geol.)

FIG. 232.—Sketch illustrating special form of pycnometer used in determination of porosity of sandstone by the acetylene-tetrachloride method.

The fragment is then crushed into its component grains and their volume determined in the same way as that described for the fragment except that before taking this reading the air bubbles adhering to the pulverized material must be removed by rotating the apparatus in an inclined position. There is a certain loss in the grinding process for which a correction must be made. The original volume, before grinding, may be calculated from the volume determined by the pycnometer after grinding, if the weights before and after grinding are determined. The original volume is obtained by multiplying the volume after grinding by the ratio of the original weight divided by the weight after grinding. The difference between the volume of the solid fragment and the original volume of the grains, divided by the volume of the solid fragment and multiplied by 100, gives the porosity in per cent.

K. B. Barnes describes a variation of the acetylene tetrachloride method of determining porosity, also utilizing the Russell burette illustrated in Fig. 232. A fragment of the sample to be tested, about 2 or 3 cm. in diameter, is first boiled in carbon tetrachloride for a period of from 1 to 3 hr. to remove any oil that may be present in its pores. A Sohlet extractor or any suitable container equipped with a reflux condenser may be used for this purpose. The residual solvent is next driven out of the specimen by drying in an electric oven or on a hot plate at a temperature not in excess of 215°F. The dry weight of the sample is then accurately determined. The specimen is then saturated with acetylene tetrachloride by immersing in a flask partly filled with the fluid, maintained under vacuum, the reduced pressure serving to evacuate air from the pores. On removal from the flask, the specimen is accurately weighed after the surplus liquid has drained from its surface and the Russell apparatus is then used to determine its gross volume. With data thus obtained, the porosity of the specimen may be computed by the formula,

(Weight in grams of saturated sample) − (weight in grams of dry sample)
÷ (volume of sample in cubic centimeters) × 100 = percentage porosity.

It should be noted that this method, since it does not involve disaggregation of the sample, indicates the "effective porosity," or that determined by the communicating pore space. Any isolated portions of the sample containing pores that do not communicate with the outer surface would remain uninfluenced by the above

described procedure. The result obtained is therefore lower than the absolute porosity obtained by complete disaggregation of the specimen.

Sizing Tests

The size of grains composing sand or sandstone strata is often of interest in correlation of formation samples from near-by wells or in recording their lithologic properties for other purposes. Coarse-grained sands and sandstones generally yield their fluid content more rapidly than fine-grained rocks, and the preponderating size of grain and range of grain sizes has an important influence on rock permeability.

In preparing a sample for a sizing test it is first necessary to disaggregate the sample into its component grains. Loosely cemented material may be crushed by application of moderate pressure in a smooth-surfaced mortar or by gently striking with a broad-faced hammer. This must be accomplished with a minimum of grinding action and yet must be sufficiently thorough to separate the component grains completely. If the grains are partially cemented with calcareous material, a dilute hydrochloric acid wash may be used partially to dissolve the secondary substance; while if the secondary material is siliceous in character, a boiling solution of caustic soda may be similarly used. An alternative method involves the use of reagents that are capable of entering the pores of the specimen as liquids and expanding on subsequent crystallization. According to Hanna and Driver,* any substance that will melt in its own water of crystallization, such as sodium acetate or sodium thiosulphate ("hypo"), may be used. Dry fragments of the specimen are placed in a suitable container with an equal amount of the crystallized reagent, a few drops of water are added and gentle heat applied until the crystals melt and enter the pores of the rock fragments. On cooling, a few crystals of the reagent are added, recrystallization occurs and the resultant expansion disintegrates the rock fragments. The method is rapid and may be repeated as often as necessary. Inspection of the sample under the binocular microscope will indicate when disaggregation is reasonably complete. Hanna and Driver also suggest that alternate freezing and thawing of the specimen would be equally effective, and, if one or another of the several types of artificially cooled refrigerators is available in the laboratory, this method may be more convenient than any other, though necessarily slow. Heating and plunging in water are also often successful in splitting apart the component grains, owing to unequal contraction on rapid cooling. If the material is particularly resistant and all of the suggested methods of disaggregation fail, resort must be had to crushing to the size of the average grain; but crushing generally results in many grains being broken and abraded and should be avoided if possible.

If chemicals have been used, the disaggregated specimen is next thoroughly washed with water on filter paper to remove them; or, if the sample contains oil, it should be leached with carbon tetrachloride or other suitable oil solvent, or treated with a solvent in the bowl of a centrifuge, such as the Dulin Rotarex described on page 461. The specimen must then be thoroughly dried in an electric oven or over a sand bath or hot plate. The weight of the disaggregated specimen is next determined with the aid of a balance sensitive to about 5 mg.

For conducting the sizing test, a series of accurately made and standardized wire-cloth screens is employed. A "nest" of 11 Tyler standard screens, ranging from 10 to 325 mesh will be suitable for the purpose. The Tyler screen scale is so designed that the width of each successive size of screen opening in the series is 1.414 times (that is, the square root of 2) the size of the opening in the next smaller size. Table

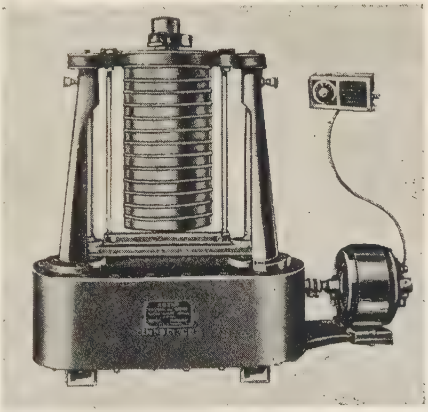
* Hanna, G. D., and H. L. Driver, The Study of Subsurface Formations in California Oil Field Development, *Summary of Operations, California Oil Fields*, vol. 10, no. 3, September, 1924, pp. 5–26 (California State Mining Bureau).

XL gives the rated mesh of screens in the series, together with the corresponding sizes of screen openings. These screens may be had mounted in shallow brass pans ranging from 6 to 12 in. in diameter and either 2⅝ or 1⅝ in. deep. The 6- and 8-in. half-height pans are commonly used for laboratory purposes. Even the smallest size is amply large for core-analysis work; for sizing tests, where only a small quantity of sample is available, a smaller size of screen would be preferable.

TABLE XL.—SIZES OF SCREENS IN THE TYLER STANDARD SCREEN SCALE

Mesh	Size of screen openings	
	Inches	Millimeters
10	.065	1.651
14	.046	1.168
20	.0328	.833
28	.0232	.589
35	.0164	.417
48	.0116	.295
65	.0082	.208
100	.0058	.147
150	.0041	.104
200	.0029	.074
325	.0017	.044

In conducting a screening test the screens are nested in the order of size, with the largest (that is, the one having the largest size of screen opening) at the top. The disaggregated, dried and accurately weighed sample is placed in the uppermost screen pan, a cover is placed on top and a receiving pan on the bottom of the nest and the screens shaken with a circular motion. In order that comparisons may be made between successive tests, it is important that a standard time and method of shaking the screens be adopted. Because of the difficulty of securing uniformity in treatment when hand-screening methods are used, it is better and less laborious to make use of a mechanical screen-shaking appliance, with the aid of which each successive sample may be subjected to precisely the same treatment. The Ro-Tap testing-sieve shaker, illustrated in Fig. 233, is a useful laboratory appliance for this purpose. This machine reproduces the circular and tapping motion given testing sieves in hand sieving but with a uniform, mechanical action, producing dependable, comparative results. With such an appliance the whole process of screening may readily be standardized to a degree not possible in hand screening.



(Courtesy of Central Scientific Co.)

FIG. 233.—"Ro-Tap" testing-sieve shaker.

After the sample has been subjected to a period of agitation within the nested screens, the component parts will be found segregated on the various screens in

accordance with their respective sizes; that is, all material coarser than 10 mesh will be retained on the uppermost screen of the series, material ranging in size from 10 to 14 mesh on the 14-mesh screen, that ranging from 14 to 20 mesh on the 20-mesh screen, and so on. Material finer than 325 mesh, which is therefore able to pass through all of the screens of the series, will accumulate in the pan at the bottom of the nest. The material retained on each screen is transferred to a suitable container and carefully weighed. From the weights of the component sizes thus determined, the percentage of the total weight of the original sample retained on each screen is next computed and the results tabulated.

A certain relationship is found to exist between the distribution of grain sizes in a sand and its porosity. Uniformity in size and shape of the grains, irrespective of their actual size, tends toward high porosity. In a mixture of grains of variable size, the fine grains occupy the interstitial spaces between the coarse and the over-all porosity is much reduced. In order to have a means of expressing the degree of uniformity in grain size of a sand, we may compute its "uniformity coefficient" from the results of a screen analysis. The uniformity coefficient is defined as the ratio of size of grain that has 60 per cent of the sample (by weight) finer than itself to the size that has 10 per cent finer than itself.* Sizes are expressed conveniently in millimeters of grain diameter.

Another useful index of grain size is that proposed by Slichter. This is called the "effective grain size," which is empirically defined as the size at the point where 10 per cent of the material (by weight) is composed of smaller grains and 90 per cent of larger grains. It may be conveniently expressed in millimeters of grain diameter. The effective grain size is a convention for indicating roughly the prevailing size of grain and the related factors, such as average size of pore spaces and resistance to flow. The resistance offered by a sand to a flow of oil through it is found to vary inversely as the effective grain size.

Permeability Tests on Oil Sands

While the saturation and porosity tests give a fair indication of the amount of oil present in an oil sand, and the grain size is to some extent an indication of the retentive properties of the sand for oil as well as the probable size of the sand pores and the resistance offered to movement of oil through them, there are additional factors that enter into flow resistance not included in these factors. The viscosity and surface tension of the oil, for example, are important variables influencing flow resistance, as is the rate of flow which is dictated by the prevailing pressure conditions. The shape of the sand grains and the nature of the surfaces that they expose to the oil are also important flow-resistance factors.

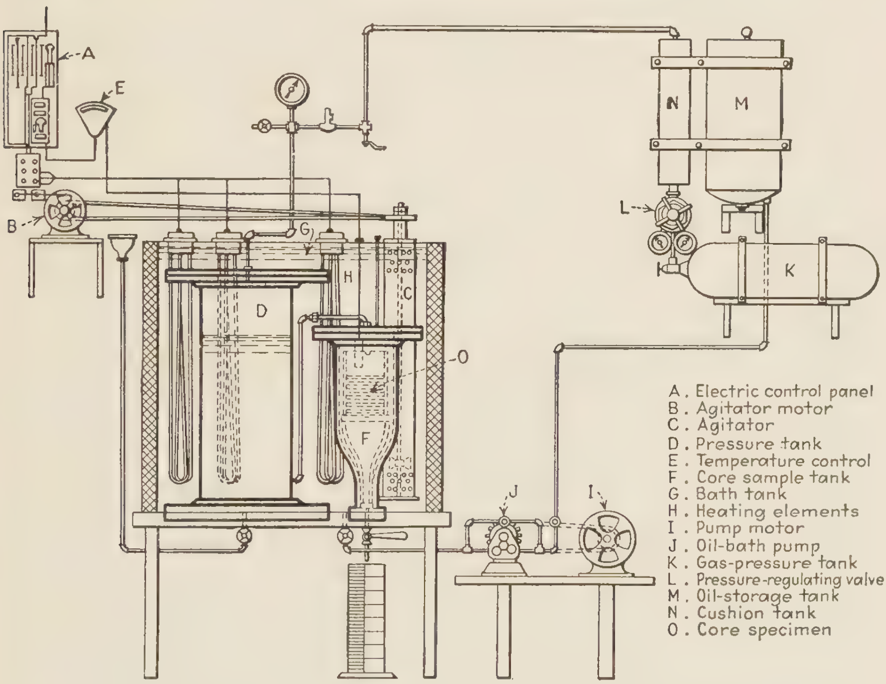
Theory and experimental results indicate that the flow of oil through the pores of a rock follows the laws of viscous flow and that Poiseuille's equation holds. It has been suggested that the unit of permeability be called the "perm," being the time rate at which a unit quantity of fluid of unit viscosity is delivered through a unit cross section and unit thickness of rock under a unit force or pressure. Dimensionally, the perm, thus defined, may be expressed in square centimeters. Application of the D'Arcy formula for liquid flow to problems of rock permeability, has led some petroleum technologists to propose that the unit of permeability be called the "D'Arcy."

Because of the large number of factors influencing flow of oil through a reservoir sand and the highly variable and intangible character of some of them, it is impossible in the present state of our knowledge of their relative influence to determine quantitatively their individual effects under a given set of conditions. We may, however,

* Meinzer, O. E., The Occurrence of Ground Water in the United States, U. S. Geol. Survey, *Water Supply Paper* 489, pp. 7, 8 and 16.

make certain useful comparisons of the permeability of different reservoir rocks for the oils they contain by observing the rate at which oil will flow through prepared samples under standardized conditions. Such tests are useful as an index of the rate at which wells producing from such reservoir rocks may yield their oil, and also of the ultimate recovery that might be expected. A highly permeable reservoir rock, for example, permits of a high rate of yield, rapid exhaustion of the oil content and high-percentage ultimate recovery. A rock of low permeability, on the other hand, would be indicative of a long productive life for the well, slow rate of decline, low rate of yield and small ultimate recovery.

Melcher has described an apparatus and method for the conduct of permeability tests which involve the use of cylindrical or disk-shaped cores of the rock to be tested,



(*After A. J. Carlson and E. E. Lawrence.*)

FIG. 234.—Apparatus for determining comparative permeabilities of core specimens.

of standard length and cross section, mounted in a suitable metal sleeve or pipe nipple in such a way that oil in a reservoir maintained at a standard elevated pressure, connected with one end of the nipple, is forced to flow through the specimen into a second reservoir maintained at atmospheric pressure.[11] The rate of flow of the oil, maintained at a standard test temperature, is taken as a measure of the permeability of the specimen for the particular oil used. Other devices for making comparative permeability tests on rock specimens make use of water or gas as the effluent.

The apparatus sketched in Fig. 234 is used in the petroleum laboratories of the University of California for making comparative permeability tests of core samples. The core section, a disk 1 in. thick, is accurately dressed and ground to fit snugly within a short pipe nipple. The space between the core *O* and the inner surface of the metal tube is filled with a cement which is impermeable to oil and holds the specimen rigidly in its position in the lower end of the nipple. Several different sizes

of swaged nipples, concentrically mounted one within another, support the nipple containing the core and permit of adapting cores of different diameters. The larger of the nested swaged nipples is screwed into a tapped opening in the bottom of tubular chamber *F*, which is connected by communicating pipe fittings with oil reservoir *D*. A standard test oil nearly fills the oil reservoir, while gas pressure supplied from high-pressure storage tank *K*, governed by regulating valve *L*, maintains a constant, standard test pressure within chamber *F* and reservoir *D*. As pressure is applied, the test oil overflows into and fills chamber *F*, trapped air being vented through a pet cock. Both *F* and *D* are immersed in an oil bath which is maintained at a standard test temperature by three thermostatically controlled heating elements *H*. Circulation of the oil bath is accomplished by a small motor-driven stirring device. The quantity of oil flowing through the specimen per minute per unit of cross section, as measured in a receiving cylinder, the standard test oil being thus supplied under constant pressure and temperature, is taken as a measure of the comparative permeability of the specimen.

Identification of Mineral Constituents of Sands

The mineral constituents of formation samples consist for the most part of grains of quartz, feldspar, hornblende, mica and other common rock-forming silicates. Less common minerals however are often present, occasionally in sufficient amount to characterize the particular horizon from which the sample is taken. The preponderance of one mineral or another, or unusual associations of various minerals, or the presence of rare minerals will often provide a means of identifying a particular stratum and of correlating it from well to well.

Color.—The general color of a sample is often an index of the nature of the prevailing mineral constituent.[9] Thus, a pure white, crystalline sand is generally composed largely of quartz. Other light-colored sands lacking the characteristic crystalline luster of quartz often contain large percentages of the feldspars or granular limestone. Micaceous minerals are easily identified by their characteristic platy cleavage and flakelike appearance. Both muscovite and biotite are common rock-forming minerals of this type, the former being white while the latter is dark brown or brownish black. Reddish and yellowish sands will usually be found to be stained with a characteristic coating of secondary iron oxide. Green sands often contain important amounts of epidote, olivine and other secondary minerals derived from the less persistent primary silicates. If clay and other decomposition products of the primary minerals are present in abundance, they will frequently be of characteristic color generally determined by the condition of the iron present. Unoxidized clays are blue, green or gray; oxidized clays are red or yellow. Such colors often provide characteristic markers that may be regionally persistent: the "red beds" of the Rocky Mountain region, and the "Big Blue" of the Coalinga region in California, for example. The color of a sand or shale will vary, depending upon whether it is dry or wet, wet minerals as a rule developing the most striking and characteristic colors.

Cleaning of Sand Grains for Mineralogic Inspection.—Sand grains are usually coated with iron or manganese compounds, lime, silica or other secondary minerals, that more or less mask their true color, transparency and crystalline form. In order that the minerals present in a sample may display their true physical properties to the observer, sands should be boiled in a dilute solution (sp. gr. 1.07) of hydrochloric acid, which removes the secondary surface material. The acid should not be permitted to remain on the sample longer than is absolutely necessary, because of the possibility of alteration of the primary minerals. The sample should be placed in an evaporating dish or beaker, covered with the dilute acid, brought to boiling, the acid immediately decanted and the sample washed with water. On hasty examination

under the binocular microscope, if it appears that the surface coatings have not been sufficiently removed, the acid treatment may be repeated.

Microscopic Inspection of Sands and Classification According to Predominating Minerals.—A quick inspection and classification of an acid-cleaned sand, according to its mineral content, may be made with the aid of a binocular microscope. A small quantity of the sand is placed on a watch glass under the microscope and the individual grains manipulated across the field with a steel needle. Familiarity with the color, crystalline form, texture and cleavage of the common rock-forming minerals will enable the observer to identify quickly the minerals composing most of the grains. A hasty record may be kept of the mineral constituents of say, 100 grains, and an approximate computation made of the percentages present for each of the common minerals. Accurate comparisons of different sands may not, of course, be made by this method, but striking and unusual percentages of one mineral or another will often be found to be characteristic of the particular horizon from which the sample comes and will provide a useful means of identification.

Isolation of Minerals of High Specific Gravity.—Investigations have shown that most of the minerals of particular value in characterizing marker horizons and making correlations have a specific gravity higher than that of quartz. In order that these heavier minerals may be more readily studied, it is convenient to have a means of concentrating and segregating them from the lighter and more common minerals with which they are associated. This separation can be approximately made by panning in water, but a more satisfactory and accurate separation is possible, especially with a small-sized sample, through the use of a heavy liquid as a separating medium.

Bromoform ($CHBr_3$), having a specific gravity of 2.88, is well adapted for this purpose and can be utilized in a simple type of apparatus. Quartz and other lighter minerals, having densities below 2.8, will remain afloat on this liquid, while the heavier minerals will slowly sink in it. The separation is conveniently accomplished with the aid of a separatory funnel. The outlet in the lower stem of the funnel is closed and the bowl above is filled about two-thirds full with bromoform. The sample of sand is then added and allowed to stand on the liquid for at least ½ hr. with frequent stirring. The heavier minerals settle very slowly but on reaching the spout of the funnel may be drained off by momentarily opening the outlet valve. The heavy minerals and small quantities of bromoform thus drained from the separatory funnel are received on a filter paper in a second funnel of common pattern and the bromoform filtered off. The mineral accumulated on the filter paper is then washed with benzol and dried by evaporation of the latter. The material is next transferred to a watch glass or glass slide and is ready for microscopic inspection.

Successive use of heavy liquids of different specific gravities may, if desired, accomplish further separation of the minerals constituting the heavy "crop" concentrated in the bromoform separation. Methylene iodide, having a specific gravity of 3.35, provides a convenient medium for separating the heavy crop into two parts, while mercurous nitrate (sp. gr. 4.3) can be employed to segregate still further the heavier residue from the methylene iodide separation. The use of mercurous nitrate necessitates heating in order to fuse the reagent. The sand specimen and the reagent are heated together over a water bath until fusion occurs, when gravitational segregation of the minerals takes place. A test tube is conveniently used for this separation, the tube being broken after the fused mass solidifies and the upper and lower portions cut apart. Dissolving of the mercurous nitrate in water will then release the minerals contained in each part.

Microscopic Determination of Minerals.—Absolute identification of the various minerals segregated by the processes outlined above is often difficult and tedious. Petrographic methods must be resorted to and the work may only be reliably con-

ducted by petrographers skilled in the special technic involved. A petrographic microscope, equipped with upper and lower Nicol prisms, condensers, revolving stage graduated to measure accurately degrees of arc, and other special features, must be used. Before identification of mineral grains under the microscope can be complete, the observer must be prepared to determine if necessary the refractive index, birefringence, crystallographic form, color, pleochroism, interference figure and other petrographic properties. It is beyond the range of this work to discuss the details of technic involved in petrographic inspection. This is properly a field for the specialist and not one with which the petroleum engineer is ordinarily expected to be familiar. The procedure to be followed is well described in books by several authorities, among others, that by Holmes* and that by Milner.†

Identification of Microfossils in Formation Samples.—The application of paleontology to the problems of correlation has within recent years been extended to include the microfossils. Fossil remnants of minute organisms, such as foraminifera, radiolaria and diatoms, are frequently found in abundance in sedimentary formations associated with petroleum deposits and they may often be observed in the formation samples secured from a drilling well. The microfossils of various forms mark different geologic horizons just as reliably as the larger fossils, and they are found to vary so distinctively within comparatively short periods of geologic time that they are now regarded as a fairly reliable means of correlating individual formational subdivisions of the different periods comprising the geologic column.

Of the various microfossils, foraminifera and diatoms are particularly useful as a means of correlation, especially the former. Foraminifera are minute organisms found in marine sediments, leaving fossil shells, usually ranging from $\frac{1}{25}$ in. in diameter to smaller sizes. They have persisted throughout geologic time from the Ordovician to the present and have been studied and chronologically classified by Cushman‡ and others. Hanna and Driver have described in detail a procedure that may be followed in separating microfossils from formation samples and in mounting them for identification and preservation (see footnote, page 468).

Diatoms are minute plants which leave siliceous fossil forms. They are found in both fresh- and salt-water deposits and have existed from the Jurassic up to the present time. They are particularly abundant in Miocene formations along the coastal plains of the North American Continent but are also plentiful in present-day waters. They are thought to be a source of petroleum deposits in some regions, those of California, for example. Diatoms have not been so thoroughly studied and classified as have the foraminifera, but Mann§ believes that they will prove a more satisfactory basis for geologic correlation than any other microfossil when all of the many types have been chronologically classified. Mann also describes methods for segregating diatoms from the formation samples in which they are found, and of preserving them and preparing them for study.

Detailed descriptions of the various types of microfossils and of the technic involved in their preparation and identification are beyond the scope of the present work. As in the case of the petrographic identification of heavy minerals, micro-

* Holmes, A., "Petrographic Methods and Calculations," D. Van Nostrand Company, Inc., New York, 1922.

† Milner, H. B., "An Introduction to Sedimentary Petrography," Murby and Company, London, 1922.

‡ Cushman, J. A., Use of Foraminifera in Geologic Correlation, Am. Assoc. Petroleum Geol., *Bull.*, vol. 8, no. 4, p. 415.

§ Mann, A., Economic Importance of Diatoms, *Smithsonian Rept.*, 1916; Suggestions for Collecting and Preparing Diatoms, *Proc.*, U. S. Nat. Museum, vol. 60, pp. 1–8, Washington, 1922.

paleontology is a highly specialized field, not properly regarded as within the scope of the activities of the petroleum production engineer. For further details of this interesting science, the reader is referred to an extensive literature to be found in the publications of the American Association of Petroleum Geologists and the related Association of Economic Palaeontologists, the U. S. Geological Survey, the various technical journals serving this general field and the numerous standard works of reference on paleontology and petrography.

Methods of Displaying Results of Core Inspection and Analyses

The foregoing pages have sketched the methods employed in selecting and preserving core samples and in conducting analytic tests thereon. The results of such tests are worthy of careful recording and thought should be given to the development of methods which will display the test data in readily assimilated form. Graphic methods are particularly appropriate and the engineer reporting results of field and laboratory studies of core samples will find it advantageous to present his data in this form as far as may be possible.

Sample Logs of Formations Penetrated in Coring.—In displaying the sequence and thickness of formations penetrated in the drilling of a well, or in coring operations incidental thereto, a graphic strip type of well log should be adopted (see pages 449 and 451). Judicious application of transparent water colors to graphic logs will add much to their appearance and assist in their interpretation. A novel method of displaying the character of material making up the formation penetrated by a well consists in preparing a graphic well log on which each stratum is represented by an actual sample of material taken from the formation samples of that horizon. For this purpose, two vertical and parallel india-ink lines are ruled, about 1 in. apart, on a sheet of heavy drawing paper or Bristol board. One-inch intervals are marked off along these lines, each 10 ft. of formational depth being represented by 1 in. on the paper. The vertical scale so established is labeled to correspond with 10-ft. intervals in the well. The position of each stratum from which samples are secured is determined on the graph by reference to the vertical scale. A thin solution of transparent, colorless mucilage or rubber cement is then evenly applied in turn to the space on the graph representing each stratum, and some of the pulverized formation sample from that particular horizon is sprinkled on with the fingers and left undisturbed until the adhesive hardens. Dilute, acid-washed, disaggregated samples are used for this purpose in order that the true character of the primary material will be apparent, and enough is applied so that the space between the India-ink guide lines is completely covered with as much as the adhesive is capable of retaining. Figure 235 presents a photograph of a sample log prepared in this way. On such a record the color, texture, size of grain and mineral content of the core material are readily apparent; and in a column at the right of the prepared log, the records of porosity, permeability, mineral determination and other tests that have been made may be recorded opposite the strata to which they relate. Such records may conveniently be maintained on 8½- by 11-in. or 8½- by 14-in. sheets and filed on edge in a suitable filing cabinet, with cotton sheeting between the individual mounts to prevent the mounted material from being rubbed off by abrasion.

A more elaborate and cumbersome system of filing away a permanent record of all formation samples is to prepare a glass slide of each, on which a small quantity of the material is embedded in Canada balsam. Slides prepared in this way have the advantage that they may be conveniently examined under the microscope at any future time, while the cardboard mounts do not lend themselves so readily to subsequent scientific inspection.

Graphic Methods of Presenting Results of Screen-sizing Tests.—Results of sand sizing tests, if presented in tabulated form, may be interpreted by the reader only

Fig. 235.—Portion of a sample log.

with difficulty. Some graphic method of presentation is almost imperative with data of this character. A simple and easily understood method of presenting the results of screen analyses is illustrated in Fig. 236. A more useful method is that of plotting cumulative percentages against the sizes of screen openings, thus showing the

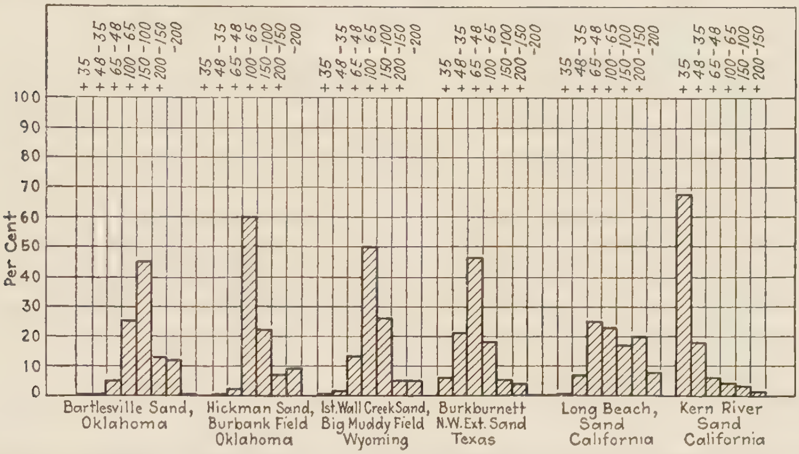


FIG. 236.—Illustrating block method of displaying results of screen analyses of formation samples.

percentages larger and smaller than each size of screen without the necessity of addition of component percentages. Figure 237 presents a series of cumulative percentage diagrams plotted on natural coordinates. Some engineers prefer to plot

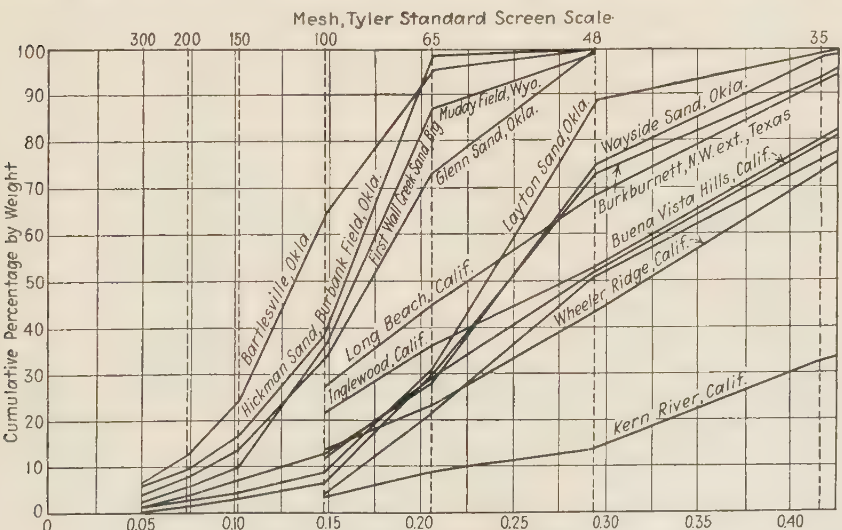


FIG. 237.—Cumulative percentage method of graphically displaying results of sizing tests.

cumulative percentage diagrams of this character on semilogarithmic coordinate paper, as illustrated in Fig. 238. The logarithmic scale permits of displaying percentages of both large and small grain sizes on the same diagram to better advantage than is possible on natural coordinates.

Graphic Method of Presenting Results of Porosity and Saturation Tests.—Porosity and oil-saturation data may be conveniently presented in the form of profiles," plotting the percentages parallel with a horizontal scale opposite corresponding points on a graphic log arranged in depth sequence. Such a method of displaying the results of porosity and saturation tests shows at a glance the strata within which the greater part of the oil is confined and suggests the points at which packers and perforated tubing should be set to confine the flow of fluids from the reservoir sand. Comparatively barren strata are equally well displayed. Taken together, these two profiles indicate quantitatively the volume of oil in each component stratum of the productive formation, and for this reason it is desirable that they both be displayed on the same graph.

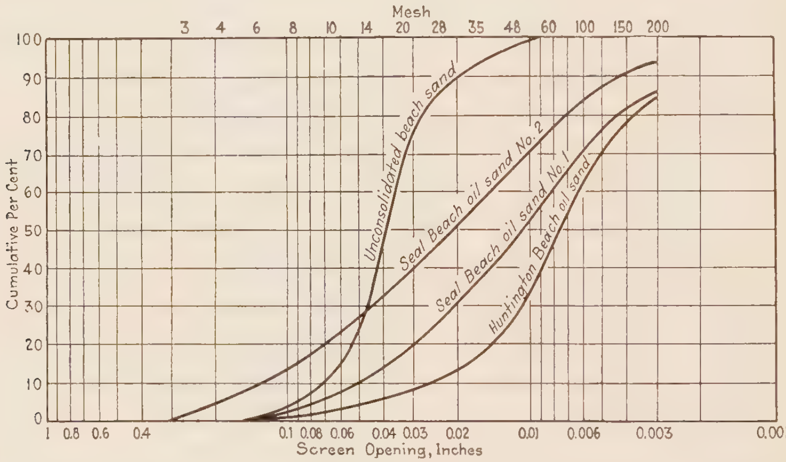


FIG. 238.—Illustrating method of plotting results of screen analyses on semilogarithmic coordinate paper.

Computation and Graphic Presentation of per Acre Oil Content of Land.—Knowing the porosity, oil saturation and thickness of each component stratum, the computation of oil content per acre is a simple matter. The formula used is as follows:

$$\text{Per acre content in barrels} = \text{per cent porosity} \times \text{per cent oil saturation} \times \frac{43{,}560 \times \text{thickness in feet}}{5.6146}.$$

The figure 43,560 is the number of square feet in 1 acre and 5.6146 represents the number of cubic feet in a barrel. Application of the formula may be simplified somewhat by using the constant 7,758.34 in lieu of the relation 43,560/5.6146. Values of oil content per acre are computed for each component stratum of the reservoir sand, and simple addition of these figures gives the total oil content per acre. It is often convenient to know the relative richness of different strata, and for this purpose the oil content per acre-foot may be computed for each productive stratum. This figure may be readily determined for each stratum in the computations of total oil content per acre, by merely segregating the product of the factors (per cent porosity × per cent saturation × 7,758.34) before multiplying by the thickness. Values of per acre-foot oil content may be conveniently displayed in graphic form by plotting values against an appropriate horizontal scale, opposite corresponding points on a graphic log. The profile so developed may be conveniently arranged on the same graph as that used for the porosity and saturation profiles, as demonstrated in Fig. 239. Total

oil content for component strata and the total oil content per acre may also be conveniently displayed opposite corresponding points on the graphic log, as illustrated

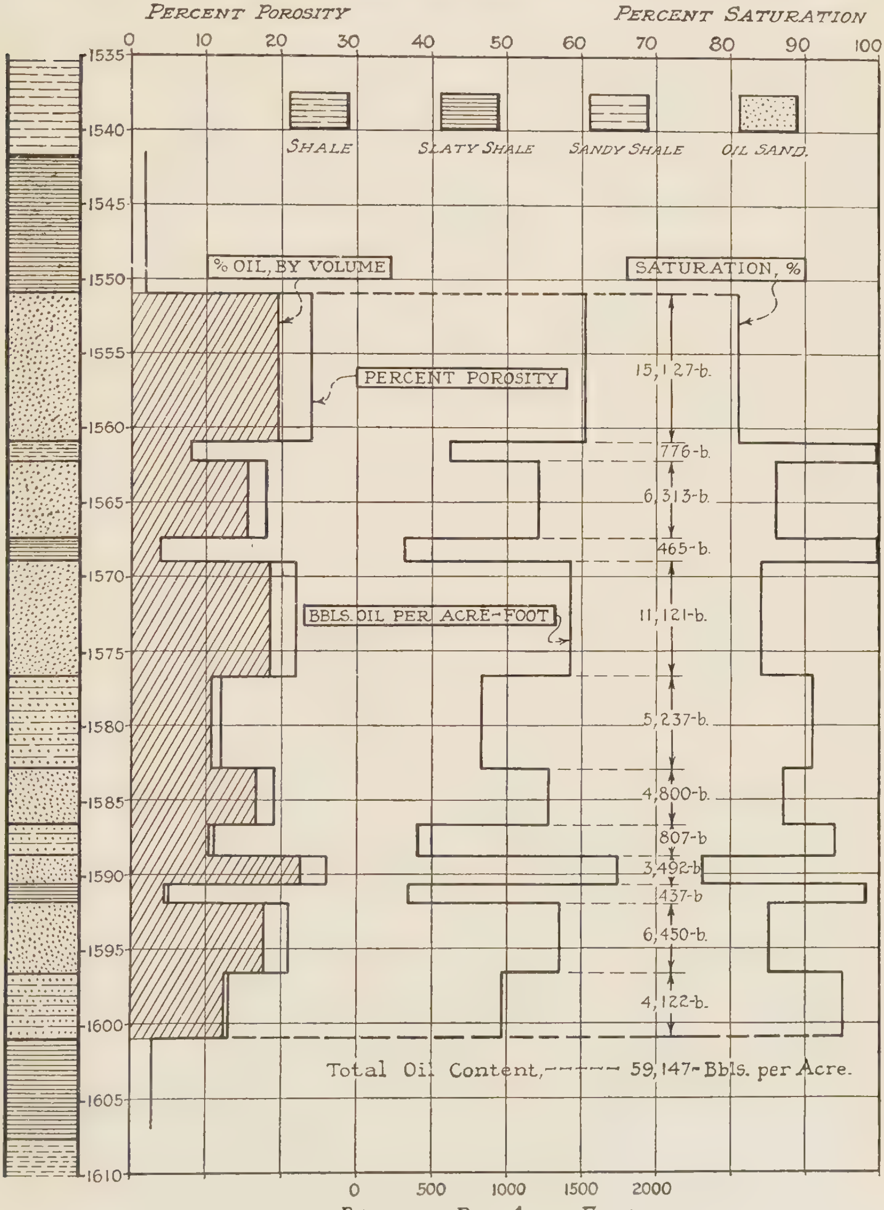


FIG. 239.—Graphic method of displaying porosity and saturation profiles.

in Fig. 239. In this way, all essential porosity, saturation and oil-content data for a given well may be displayed in graphic form on a single page. If desired, two additional profiles showing water saturation in per cent and water content per acre may

also be drawn. Use of appropriate tints to characterize the different profiles will permit of all being placed on one page without confusion in interpretation.

ELECTRICAL CORING

A method of determining the electrical resistivity properties of rock strata penetrated by a well, developed by C. and M. Schlumberger and associates,* has found use in many fields. By this method a continuous record is secured throughout the full depth of a well of variations in resistivity which, when correlated with a graphic log of the formations arranged in depth sequence, gives what has been called an "electrical log" of the well. Rock resistivity is the inverse of electrical conductivity. It is measured by lowering three non-polarizing electrodes suspended on a three-wire insulated cable, to different depths in an uncased well full of mud fluid, developing a flow of direct current from the lowermost electrode into the wall rock opposite and measuring the difference in potential between the other two electrodes with the aid of a potentiometer situated on the surface. The battery that furnishes current to the lowermost electrode has one pole grounded near the well head.

(*After C. and M. Schlumberger in Proc., World Petroleum Congress*, 1933.)

Fig. 240.—Schlumberger "electrical log" of a well showing "porosity" and "resistivity" profiles characterizing three productive horizons in the Boldesti field, Roumania.

The extent to which the formations are penetrated by the current depends to an important degree upon the saline content of the water present in the rock pores. Formations containing oil or gas and little water display very high resistivities. Suitable corrections must be applied to correct the observed potentiometer readings for variations in ground temperature. Two different parameters are recorded as a part of the electrical log: (1) the resistivity profile, and (2) the porosity profile. The latter is an expression of electrofiltration effects secured when sufficient hydrostatic head exists within the mud fluid in the well to cause movement of fluid from the well into the formation.

* Schlumberger, C. and M. and E. G. Leonardson, *Tech. Pub.* 462, 503 and 505, Am. Inst. Mining Met. Eng., 1932–1933.

Figure 240 presents a typical electrical log and illustrates characteristic variations in the porosity and resistivity profiles. Remarkable correlations are frequently secured between electrical logs in near-by wells, so that structural relationships are clearly defined. Proponents of the method claim that under favorable circumstances the electrical log becomes a complete substitute for mechanical coring. The Schlumberger electrical coring apparatus, with minor variations, also affords a convenient means of making well surveys and of locating points at which water enters a well.

ANALYSIS OF GROUND WATERS

Many of the petroleum engineer's problems are concerned with ground waters, and a knowledge of their chemical characteristics is often essential in the conduct of various field operations. As explained in Chap. X the nature of the dissolved salts present in the ground waters varies markedly at different depths, and chemical analyses of the waters have provided a convenient means of correlating strata encountered in different wells. The salts present in ground waters may exert an important influence in determining the success of oil-well cementing operations, or they may have a bearing upon the rate of deterioration of well casing, tubing or other well or surface equipment with which they may come into contact. Water incursion into a producing well is regarded as a menace to continued production. Often it can be excluded if its source is known, and if the saline content of the waters encountered in different strata during the drilling of each well is recorded, their subsequent identification is facilitated. In some oil-producing regions it is found that the nature of the dissolved salts bears a certain relationship to the proximity of oil-bearing sands within the formation in which they occur and may be used to some extent as a basis for prediction or geologic surmise in petroleum exploration.

The importance of these applications in the work of the petroleum production engineer requires that he be familiar with the methods of making and interpreting water analyses, and he should have at his command in the field laboratory the necessary facilities and reagents for making water analyses.

While many different substances may be present in ground waters, often in important amounts, the number of chemical elements and radicals in which one is normally interested in the applications suggested above can be reduced to comparatively few. These are the carbonates, bicarbonates, chlorides and sulphates of the strong alkalies, sodium and potassium, and of the alkaline earths, calcium and magnesium. A knowledge of the relative amounts of these substances will ordinarily be all that will be required in determining the chemical activity of a ground water, so that its probable reaction under any conditions may be predicted; or so that its true character may be determined for comparative purposes. In some fields it may be found that some less common or ordinarily less abundant substance, such as iron, strontium, barium,

lithium, iodine, bromine or sulphur in the form of sulphide, is present in abnormal amounts in the ground waters of particular horizons. Space does not here permit of discussion of the routine of water analysis, and the interested reader is referred to standard works of reference on this subject.

Methods of Reporting and Displaying the Results of Ground-water Analyses.—The results of water analyses are customarily reported in milligrams per liter, grains per gallon, or parts per million. If the amounts of the various elements and radicals have been determined in grains per gallon, as is the custom of many analysts, the equivalent in milligrams per liter (or parts per million) for each constituent can be determined by multiplying the figures representing grains per gallon by 17.12. Such an analysis, giving merely a statement of the amounts of different substances contained in a given quantity of the sample, is of little value as an expression of its real chemical character. Usually a number of different substances are present, but a mere recital of their amounts would be of little value in determining their reacting value with any particular substance with which they might be brought into contact, or in making intelligent comparisons between different ground waters. For example, samples of the same water, diluted to varying degrees of concentration, would appear as essentially different waters if merely the absolute values of their saline constituents were compared. If, on the other hand, we express the amounts of the various constituents on a percentage basis, a more reliable means of comparison is afforded. This is essentially what is done in determining the "reactive capacity" of the various constituents.[28]

The reactive value of an element or radical is the quotient obtained by dividing the actual weight of the substance present in solution by its atomic weight. We may conveniently arrive at an equivalent result by multiplying by the reciprocals of the atomic weights, these reciprocals being termed "reaction coefficients." The reaction coefficients of the elements and radicals commonly present in ground waters are given in Table XLI, here classified according to the character of their ionic charges.

TABLE XLI.—REACTION COEFFICIENTS OF ACTIVE ELEMENTS AND RADICALS COMMONLY FOUND IN GROUND WATERS

Positive Radicals	Reaction Coefficients	Negative Radicals	Reaction Coefficients
Sodium (Na)	.0435	Sulphate (SO_4)	.0208
Potassium (K)	.0256	Chloride (Cl)	.0282
Calcium (Ca)	.0499	Nitrate (NO_3)	.0161
Magnesium (Mg)	.0822	Carbonate (CO_3)	.0333
		Bicarbonate (HCO_3)	.0164
		Sulphide (S)	.0624

Table XLII presents the results of a typical ground-water analysis and figures indicating the method of computing the reacting values.

The sum of the reacting values of the positive radicals computed for a ground-water analysis must necessarily equal (approximately) the sum of the negative reacting values. After the reacting values have been computed, their percentages are determined by dividing each by the total of all of the reacting values represented in the analysis. Table XLIII illustrates the method of computing the percentages for the analysis presented in Table XLII.

When a water analysis is expressed in percentage reacting values in the manner indicated in Table XLIII, all arbitrary units of measurement are dispensed with. Expressed in this form, the analysis becomes essentially a chemical formula, based entirely upon fundamental chemical laws. Expression of the results of analysis in percentage reacting values permits of ready and direct comparisons not possible by other means.

TABLE XLII.—ILLUSTRATING METHOD OF COMPUTING REACTING VALUES

Radicals	Parts per Million		Reaction Coefficient		Reacting Values (Equivalent to Milligrams of Hydrogen)	
Sodium (Na)	1003.2	×	.0435	=	43.64	
Calcium (Ca)	17.3	×	.0499	=	.86	
Magnesium (Mg)	8.7	×	.0822	=	.71	
						45.21
Sulphate (SO_4)	230.4	×	.0208	=	4.79	
Chloride (Cl)	54.5	×	.0282	=	1.54	
Carbonate (CO_3)	1067.0	×	.0333	=	35.53	
Sulphur (S)	51.7	×	.0624	=	3.23	
						45.09
						90.30

TABLE XLIII.—ILLUSTRATING METHOD OF COMPUTING PERCENTAGE REACTING VALUES

Radical	Reacting Values			Per Cent	
Sodium	43.64	90.3	=	48.3	
Calcium	.86	90.3	=	.9	
Magnesium	.71	90.3	=	.8	
					50
Sulphate	4.79	90.3	=	5.3	
Chloride	1.54	90.3	=	1.7	
Carbonate	35.53	90.3	=	39.4	
Sulphide	3.23	90.3	=	3.6	
					50

Graphical Representation of Water Analyses.—When water analyses are expressed in percentages of ionic constituents, as explained above, the results can be conveniently expressed in graphic form by plotting them on hexagonal coordinates. Connecting the points so plotted with straight lines produces a geometric figure, the form of which conveys in a graphic way, a visual impression of the chemical nature of the water which the analysis represents. Figure 241 illustrates the method of constructing such graphs and presents several graphs of typical oil-field ground waters.

The Stabler-Palmer System of Chemical Hydrology.—H. Stabler of the U. S. Geological Survey proposed and Chase Palmer of the same organization later developed and applied, a system for the geochemical interpretation of water analyses that has since been widely used in studying oil-field ground waters. The method is one which seeks to express the analysis in terms of reactive power and chemical character rather than by ionic content.[31]

The reactive power of a ground water is dependent upon the extent to which chemically active substances are present. These are of two general types: those which produce salinity and those which produce alkalinity. Both of these properties are induced in varying degree by different elements and radicals. The strong acids, combined with an equal reacting value of the primary bases, induce a property called "primary salinity"; combined with the alkaline earths they produce "secondary

salinity." Primary alkalinity and secondary alkalinity are determined respectively by the excess of the alkalies or alkaline-earth bases over the reacting values of the strong acids. From the chemical analysis of a ground water the reactive values of the different components are computed, as explained above, and the total percentages of the different components causing primary and secondary alkalinity and salinity are determined. Table XLIV indicates the manner of computing the values representing primary and secondary alkalinity and salinity, once the percentage reacting values for

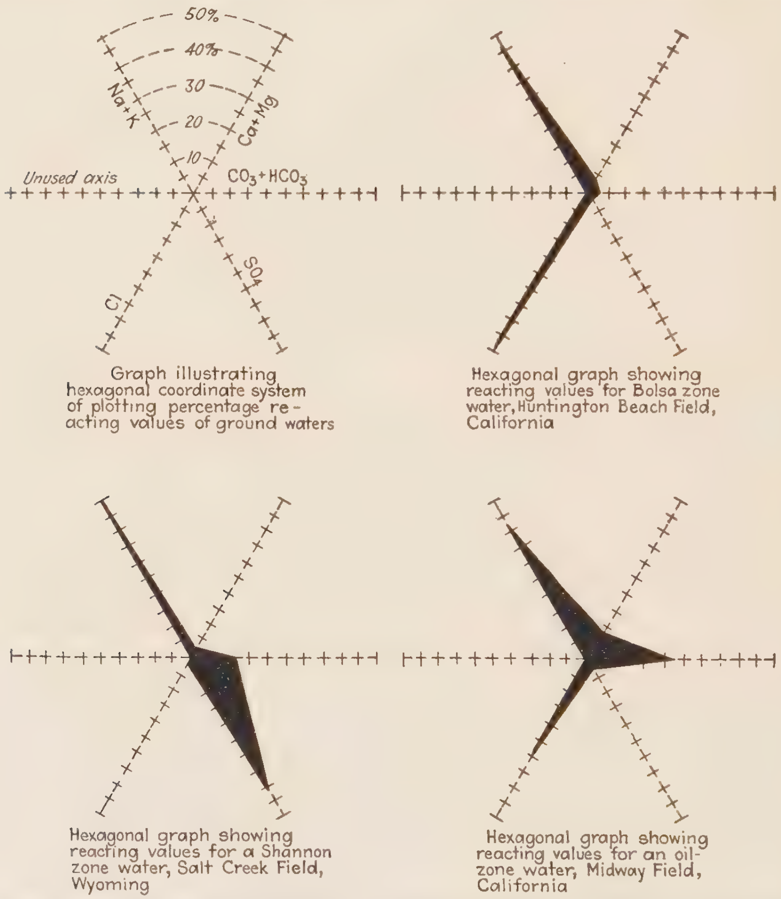


FIG. 241.—Graphs illustrating hexagonal system of displaying results of water analyses. (Method suggested by F. G. Tickell.)

all components have been determined. The water-analysis data presented in Tables XLII and XLIII are again used as a means of indicating the method of computation.

Graphic Method of Displaying Character Analyses.—Figure 242 illustrates a convenient method of graphically determining and displaying the saline and alkaline characteristics of ground waters as provided in the Stabler-Palmer system. Here, by a system of hachuring applied to scaled areas representing the different ionic constituents, which will be readily understood on inspection of the illustration, the relative values of primary and secondary alkalinity and salinity are directly determined.

TABLE XLIV.—SHOWING METHOD OF COMPUTING SALINITY AND ALKALINITY VALUES IN THE STABLER-PALMER SYSTEM

Primary salinity:

(SO_4 + Cl) plus an equal value of Na and K = (5.3 + 1.7) × 2 = 14.00.

Secondary salinity:

If (SO_4 + Cl) is greater than (Na + K), then (SO_4 + Cl) plus an equal value of (Ca + Mg) = ...*

Primary alkalinity:

Excess of (Na + K) over (SO_4 + Cl) plus an equal value of CO_3† .... = (48.30 − 7.00) × 2 = 82.60.

Secondary alkalinity:

Excess of (Ca + Mg) over (SO_4 + Cl) plus an equal value of CO_3† ...... = (.8 + .9) × 2 = 3.40.

* (SO_4 + Cl) not greater than (Na + K) in this case.

† If sulphide or bicarbonate is recorded in the analysis, it is added to the CO_3 content.

WELL-SURVEYING INSTRUMENTS AND METHODS

It is important that wells be drilled vertically and straight for a variety of reasons. Our system of property ownership requires that line wells do not depart from the vertical and illegally encroach on neighboring properties. The practice of spacing wells apart at equal distances to secure uniform drainage loses its significance if the wells are crooked. The wells develop interference, and a lower over-all percentage extraction of the available oil is secured than if the wells penetrate the productive horizon at uniformly spaced points. If the record of thickness of formations penetrated is of importance in geologic correlation studies, departure of a well from the vertical will be productive of very misleading information. Some confusing pictures have been presented where crooked holes only a few hundred feet apart at the surface have shown great differences in depth and thickness of marker horizons and remarkable differences in productivity on completion. Edge wells may be deflected and entirely miss the productive sands. A well on good acreage may drift into poor

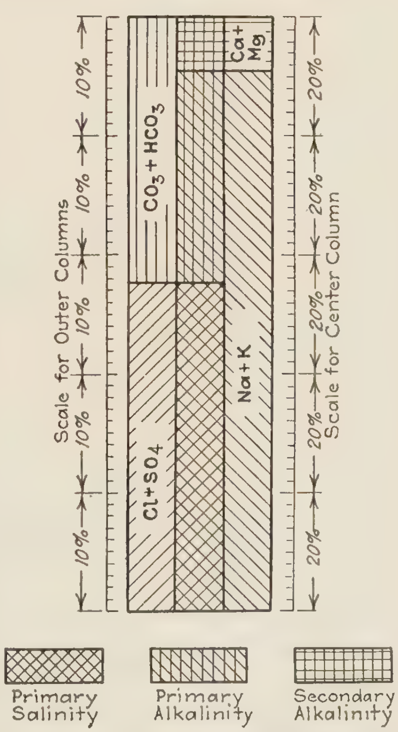


FIG. 242.—Graphic representation of character analysis of the upper edge water, Santa Fe Springs field, California.

neighboring acreage and *vice versa*. Proper correlation is important in determining points at which strings of casing are to be set and cemented and in estimating depth to production.

In drilling and casing wells, a crooked hole introduces mechanical difficulties, at times even requiring abandonment of the well. Twist-offs of the drill pipe are more common, and the resulting fishing jobs are more difficult and costly. More sidetracking jobs are necessary. There is greater power consumption in rotating drill pipe in a crooked hole owing to excessive friction. It is difficult to insert casing, and the casing may be damaged in adapting itself to abrupt changes in direction. It is often difficult to operate cable tools in a crooked hole: the casing may become "line cut" and collapse, owing to the drilling cable and sand line always scraping on one side. Crooked holes on adjoining locations sometimes come too near each other and one loses circulation to the other, perhaps causing mudding of the productive sands about one well by the other. In some instances wells have actually intersected. A crooked hole requires the drilling of greater footage to reach a given depth than would be necessary in a straight hole and the cost of drilling this additional footage and time lost are important considerations.

A crooked well is also productive of difficulties during the operating stage, particularly if it is to be pumped. The column of sucker rods rests against the tubing—always against one side in a crooked hole—and its oscillating movement wears holes in the tubing and wears away the metal about the screw joints by which the individual rods are held together. There is undue wear on the pump plunger and excessive power consumption due to frictional losses. Fishing troubles in recovering parted rods are accentuated. In pumping, there is considerable elastic movement of the tubing, with resulting wear of the tubing collars and casing—all on one side if the hole is crooked.

Since crooked holes are the cause of so many difficulties, it is important that the operator have some reasonably accurate method of estimating to what extent the wells depart from the vertical and just where deflections occur in the course of each hole. A means must be provided for determining at any point the inclination of the axis of the well from the vertical, as well as the direction and distance, both vertically and horizontally, of any point in the well from the starting point at the surface. Need for information of this character has led to the development of a variety of well-surveying instruments, several of which are finding practical application in oil-field work. Space permits of brief descriptions of only a few of the more commonly used and characteristic types of well-surveying instruments. For more complete descriptions the reader is referred to the bibliography at the end of this chapter.

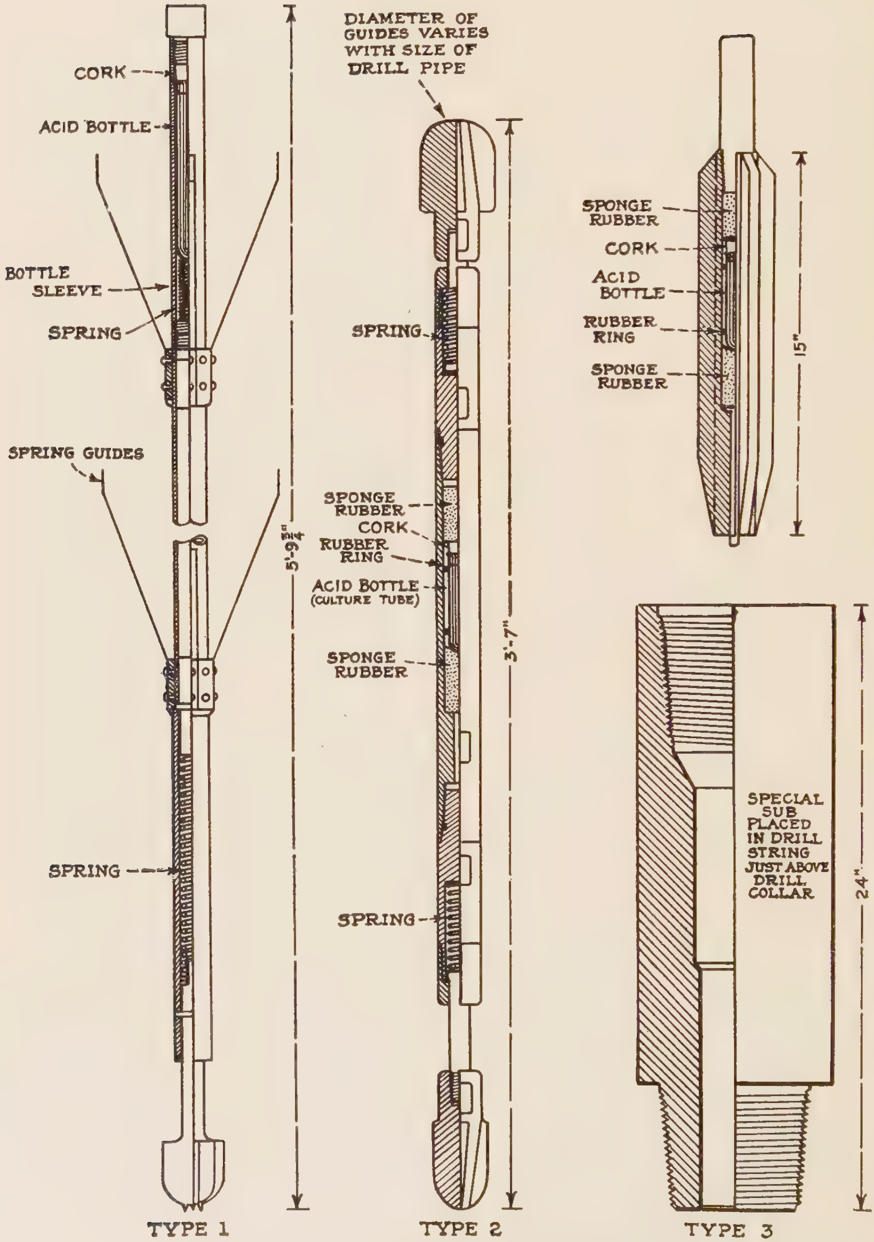
Types of Well-surveying Instruments

Well-surveying instruments are of two types: those recording vertical deviation only and those recording both the amount and direction of the deflection. The former are called "clinographs" and the latter "directional clinographs." Clinographs determine the amount of the deflection either by recording the position of a liquid surface or a gas bubble floating on a liquid surface, or the angle of inclination of a pendulum with respect to the axis of the well. Directional clinographs measure the direction of the deflection either by a process of orienting the drill pipe or tubing on which the device is suspended in the well, or with the aid of various forms of compasses. The records are made either by photographic, chemical, electrical or mechanical means. Instruments designed to indicate only the amount of the deflection from the vertical are comparatively simple and easy to operate. Others, which show both the amount and direction of the deflection and which afford a means of determining the azimuth of any point in the well with respect to the starting point at the surface, are more complicated and require experienced and specially trained engineers for their operation as well as in the interpretation of the records resulting from their use. For this reason, most of the directional well surveying is done by individuals or companies specially equipped for this service and the work is done by specially trained engineers.

The charges for this service range from 6 to 12 cts. per foot of depth of hole surveyed, the price depending upon the type of instrument used, the location of the well and the equipment at the derrick for making the survey. Some of the instruments are also rented by the month or year or are sold outright to the oil or drilling companies for use by their own engineers. Most of the instruments are patented or have patents pending.

The Hydrofluoric Acid Bottle Inclinometer.—One of the simplest and most used methods of determining the amount of deviation of a well from the vertical involves the use of a little hydrofluoric acid in a glass bottle. If a cylindrical glass bottle partly filled with the acid is lowered to the point in the well at which the deflection measurement is desired and held at rest for 10 or 15 min., the level surface of the liquid will etch its position on the glass wall of the bottle, the axis of which is maintained in a position parallel to or coinciding with the axis of the well. When the bottle is subsequently withdrawn, the angle between the etched ellipse (marking the position of the acid surface while at rest in the well) and a circular cross section of the container is taken as a measure of the inclination of the well from the vertical. The etched ellipse on the inside surface of the glass bottle is sometimes a little "fuzzy," due to movement of the fluid during its trip into and out of the well, but the position of the liquid while at rest in the test position is clearly apparent if allowed to stand long enough.

Hydrofluoric acid is supplied by the manufacturers in wax bottles. In use, the concentrated acid is diluted with about an equal amount of water and placed in a cylindrical glass bottle about 1 or 2 in. in diameter. The bottle is placed in a steel



(*After R. D. Copley in Am. Petroleum Inst., Bull.* 208.)

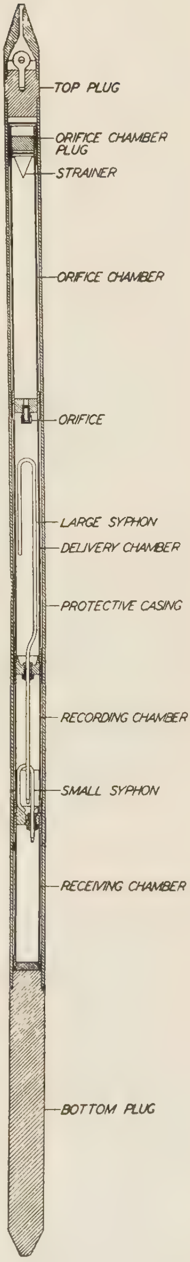
FIG. 243.—Types of acid-bottle inclinometers.

container made secure against high external hydrostatic pressure. This is lowered into the well on the sand line normally provided for operating the bailer in a "standard" or "combination" rig; or, it may be lowered through rotary drill pipe on a steel wire. One type of acid-bottle container is designed for use as a "go-devil," being simply dropped into the rotary drill pipe at the surface and allowed to sink to bottom through the drilling fluid. Go-devils are preferably of such diameter that they may not fall freely through the mud fluid in the drill pipe. Sometimes they must be pumped down with the drilling fluid. They are often equipped with rubber supports or a plunger device to cushion the bottle and absorb the shock delivered when it comes to rest on the upper end of the bit (see Fig. 243). They are generally used immediately before drawing out the stem to replace the bit so that they are in the well but a few hours at most.

The angle that the etched ellipse on the inside surface of the glass bottle makes with a plane at right angles to the axis may be read directly with the aid of a goniometer, or it may be computed by trigonometric methods from measurements of the inside diameter of the bottle and the distance between the high and low points of the etched line when projected on a plane parallel with the axis of the bottle. Another method involves the use of a strip of sensitized paper, which is wrapped tightly around the etched tube, starting at the high point of the etched line. The interior of the tube is then exposed to a light and the etched ellipse printed in the form of a curve on the sensitized paper. From this photographic record the amplitude or height to which the curve rises above its base is measured. This measurement, in conjunction with the diameter of the bottle, affords a means of computing the angle of deflection of the well. The meniscus formed by the acid in its contact with the glass wall of the bottle often makes somewhat uncertain the exact position of the acid surface while at rest in the well. This difficulty may be largely overcome by floating a little light lubricating oil on the surface of the acid, which tends to reduce the concavity of the meniscus.

Acid-bottle methods of measuring well deflections are probably not accurate within several degrees in many cases, and they are useful only in determining the amount and not the direction of deflection of the well. They have the advantage of simplicity, however, and have been widely used in well surveys in the American oil fields.

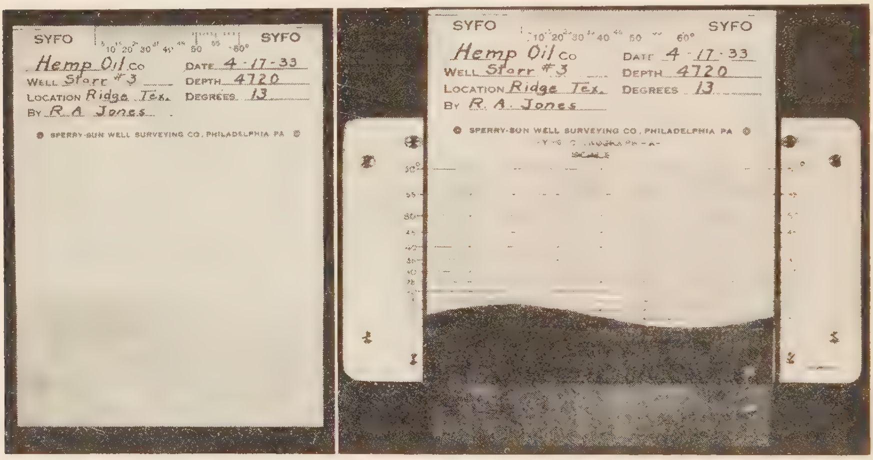
The Syfo Clinograph.—This instrument, like the acid bottle, operates on the principle of measuring the angle between a horizontal liquid surface and the axis of the well. Instead of acid a harmless dye solution is employed, leaving an impression of the level surface of the fluid on a paper chart so adjusted as to form a cylinder on the inside of the recording chamber. The dye solution remains in the recording chamber only a few seconds while making the record. The instrument comprises a brass cylinder which is divided into four compartments, one above another (see Fig. 244.) The brass cylinder is supported in an outer protective casing closed at both ends with steel



(*Courtesy of Sperry-Sun Well Surveying Co.*)

FIG. 244.—Vertical section through Syfo Clinograph.

plugs. The uppermost of the four compartments contains a supply of ink or dye, which is permitted to flow slowly through an orifice into a second compartment. The latter is equipped with a siphon, so formed that when the ink reaches a certain level, it is suddenly siphoned into the third compartment or recording chamber. The walls of this compartment support the paper record chart, cylindrical in form, upon which the ink leaves an impression of the position of the level surface of the fluid while the device is at rest in the well. On rising to a certain level in the recording chamber, the ink is transferred by means of a second siphon into the lowermost compartment, in which it is stored until the instrument is withdrawn to the surface. The time that must elapse before the fluid enters the recording chamber is controlled by the size of the orifice between the first and second compartments, several different sizes of orifice disks being provided with the instrument. One is



(*Courtesy of Sperry-Sun Well Surveying Co.*)

FIG. 245.—Record made by the Syfo Clinograph.

Right: Illustrating method of determining inclination with the aid of a graduated reference scale.

selected which gives sufficient time to assemble the instrument and lower it to the desired position in the well before the record is made. The instrument may either be used as a go-devil, or it may be lowered on the sand line or measuring line.

On removal from the instrument after withdrawing it to the surface, the paper cylinder, upon which the record has been made, is unrolled and measurements are made indicating the vertical distance between the high and low points on the ink-coated record (see Fig. 245). By reference to a scale printed on the top of the chart, this measured vertical distance may be quickly converted to degrees of inclination. As a further aid to rapid conversion, for angles up to 10 deg. the charts are ruled horizontally, it being only necessary to count the number of horizontal lines between the high and low points on the ink-coated record, the number of scale divisions indicating directly the number of degrees declination.

Syfo instruments can be obtained in three sizes: size AA with 1⁵⁄₁₆-in. outside diameter casing; size A with 1.9-in. outside diameter casing, and size B with 4.5-in. outside diameter casing. These instruments attain an accuracy of 1, ½ and ¼ deg., respectively. The device is leased by the month or year.*

* The author is indebted to G. L. Kothny of the Sperry-Sun Well Surveying Company for the descriptions of the Syfo Clinograph and Surwel Clinograph, presented in this chapter.

The Hydril angle indicator is designed for use as a regular part of the drill-pipe column used in rotary drilling, being placed in a special sub carried in the drill pipe immediately above the drill collar. Circulation of drilling fluid is not restricted. A single record of declination of the hole may be made before starting drilling operations after replacing a bit, or just before drawing out the stem after completion of a period of drilling. The instrument indicates the amount of deflection of the well from the vertical at any point, by mechanically recording the position of a plumb-bob which hangs from a universal joint in an oil bath. The plumb-bob has an upward-extending arm surmounted by a serrated die crown. Screwed into the upper end of the instrument is a packing-gland assembly through which passes a piston rod attached to a sliding head within the body. On the underside of the head a concave metallic disk is removably attached. The lower spherical surface of the disk is marked off in concentric circles, each representing an increment of 2 deg. in declination. When in a vertical position, the longitudinal axis of the instrument passes through the center of the record disk and also that of the pendulum. Upon the instrument being inclined, however, the pendulum maintains its vertical position and the record disk, being fixed in its relation with the axis of the instrument, assumes an inclined position.

The angle indicator is operated by the pressure of the circulating fluid, which depresses the piston and forces the record disk against the die crown, making an indentation which indicates the deflection of the pendulum. After making the impression on the record disk, the mechanism is automatically locked, so that no additional marks will be made. When the impression is made before drilling, a light metal disk-shaped "pressure cap" is attached to the upper end of the piston rod, partially restricting passage of the drilling fluid. When circulation starts, the piston is depressed until the record disk is penetrated by the die crown on the top of the pendulum arm. The pressure cup is then folded down over the piston head by the force of the fluid, leaving the passage for drilling fluid fully open. Drilling then proceeds in the usual manner and the instrument and record are not withdrawn until it is necessary to change the bit. When the reading is to be taken after drilling, the pressure cup is left off and just before starting out of the hole the kelly joint is disconnected and a metal ball dropped into the drill pipe. The kelly is then replaced and the ball pumped down until it reaches the instrument and depresses the piston, thus making the record. Momentary slowing of the pump shows when the ball strikes the plunger.

The Hydril angle indicator is very similar to the Elliott drift indicator, the principal difference being that in the latter instrument, the record disk is supported beneath the point of the pendulum and the pendulum itself is depressed to make the record.

Methods of Determining Direction of Deflection

The well-surveying devices described in the foregoing sections are designed to measure only the amount of deflection from the vertical and not the direction of declination. The amount of deflection, expressed in degrees, is all that is required in most cases, but where a complete survey of a well is necessary, a means must also be provided for determining the direction of declination. For this purpose we may make use of either of two methods. First, we may attach the instrument to a column of tubing or rotary drill pipe and orient the pipe into the well—a process which involves determination and recording of the extent to which the pipe supporting the instrument twists as it is lowered. Secondly, we may measure the direction of deflection by reference to a magnetic needle

or a gyroscopic compass. Both of these methods are applied in various instruments used in well surveys. Both have their disadvantages, but either method is probably reasonably accurate when applied by a careful operator with instruments of suitable design.

Orienting Drill Pipe or Tubing into a Well.—In determining the direction of deflection by orienting drill pipe or tubing supporting a deflection-recording instrument, the procedure varies somewhat in detail, but the objective is always the same. The sole purpose is to measure the amount of axial rotation of the pipe, relative to the points of the compass so that the position of the mechanism supported at the lower end, which measures the amount of deflection, can be determined at any time. In one commonly used method a pair of clamps is attached near the upper end of each stand of pipe after the joint which connects it to the column in the well has been securely tightened. The upper clamp supports a telescope or sighting bar, which is supported on a vertical standard in such a way that the line of sight is in a plane parallel with the axis of the pipe. The upper clamp rests upon the lower clamp, which is graduated in degrees of arc and may be rotated about the pipe and clamped in any desired position. A pointer on the upper clamp, on a radial line through the center of the standard which supports the telescope or sighting bar, is immediately over the graduated arc on the lower clamp. After adding a new stand of pipe to the column in the well, the clamps are placed about the new section of pipe near its upper end and rotated until the line of sight of the telescope or sighting bar is upon a selected, distant object which serves as a reference point. The lower clamp is then tightened on the pipe with the pointer on the upper clamp over the zero point of the graduated arc. The column of pipe is then lowered until the clamps are a few feet above the derrick floor and a new stand of pipe connected. If rotation of the pipe occurs, as will usually be the case, the upper clamp is rotated until the telescope or sighting bar is again in line with the distant reference point. The pointer then indicates on the graduated scale of the lower fixed clamp the number of degrees that the pipe has rotated. Another pair of clamps is then adjusted on the upper end of the new stand of pipe with its telescope aligned with the reference point. This procedure is repeated, stand by stand, as the pipe is lowered into the well and a record kept of the amount of rotation. The accuracy of the work may be checked if desired by reversing the process as the pipe is withdrawn from the well.

Another method of orienting pipe involves the use of a surveyor's transit, which is set up outside the derrick and accurately leveled so that the telescope swings in a vertical plane on its supports, and the vertical cross hair of the instrument is centered on the lower end of the drill pipe or tubing. The first stand of pipe, with the well-surveying instrument attached to its lower end, is suspended in the derrick and the pipe turned until the reference plane or point of the instrument is in line with the vertical cross hair of the transit. With the pipe held firmly so that it may not rotate, a clamp carrying a fixed target is attached to the upper end in such a way that the target is also centered on the vertical cross hair of the transit. The two reference points being now in the same vertical plane, the pipe is lowered into the well until the clamp and target are 2 or 3 ft. above the derrick floor. A new stand of drill pipe or tubing is then assembled and connected to that in the well and the column turned by hand until the target on the clamp is again in line with the cross hair of the instrument. A second clamp and target are then attached to the upper end of the new stand, in line with the first, as determined by the transit. This procedure is repeated with each successive stand until the instrument has reached the point in the well where a reading for declination is to be made.

There has been considerable discussion among engineers engaged in well surveying, concerning the reliability of surveys based on the practice of orienting the drill pipe.

Some claim that a column of pipe is twisted on lowering it into a crooked hole where there is considerable wall friction, with the result that there is no relation between the direction of a radial plane through a certain point on its circumference at a depth of several thousand feet and the direction that this plane assumed at the surface. It seems reasonable to expect that any turning of the pipe, as it enters the well, will develop torque in the pipe, which will be partially offset by wall friction, with the result that the computed position of the reference plane through the surveying instrument in the well, based on surface observations, may not correspond with its actual position. This view is opposed by some engineers who believe that whatever torque is given the drill pipe at the surface will be transmitted in equal amount to the bottom, thus preserving the orientation of the instrument. They point to numerous records where by repeated tests in the same well, utilizing this method, the records closely check. This is not always true, however, for there are other instances where holes surveyed by different engineers, using different devices, have varied widely in the reported direction of deflection. One engineer finds that about four out of six measurements check where the direction of deflection is determined by orienting drill pipe; but, as he points out, it may be that the same errors are repeated in each test and that there is no assurance that the average reading is correct. However, some of the most active and successful engineers engaged in oil-well surveying use this method.

Use of the Magnetic Compass in Orienting Well Surveys.—A number of well-surveying instruments make use of various forms of magnetic compasses as a means of recording the direction of deflection of a well. The magnetic compass always points to the magnetic north, irrespective of the orientation of its supporting mechanism, unless disturbed by local magnetic irregularities. Consequently any instrument which combines means of securing a record of deflection of a well from the vertical with a record of the horizontal angle of deflection of the axis from an assumed reference line—such as a north-and-south line—affords a means of completely mapping its course. The magnetic needle provides a simple and direct record of the direction of deflection, providing the needle always points in the same direction while in the well. Many engineers believe that it does not. It is well known that drilling tools and drill pipe often become highly magnetized in normal use. Oil-well casings are often highly magnetic. Bodies of magnetic minerals in the formations penetrated may also cause local disturbance of the magnetic field. Many believe that these magnetic irregularities would have sufficient influence on a compass needle lowered in a well to make the compass unreliable as a direction finder.

It is generally agreed that a compass needle is not dependable when operated in a steel or iron casing which tends to shield it from the earth's magnetic field, and where used in well-surveying instruments they are accurate only in open hole or in tubing made of non-magnetic material.

Use of Gyroscopic Compass as a Means of Orienting Well Surveys.—A gyroscope comprises a rotating wheel supported in such a way that it is free to move about three different axes. When caused to rotate rapidly about one of these axes, it is capable of maintaining its original plane of rotation in space, irrespective of changes in inclination of the supporting mechanism. This property of the gyroscope provides a useful means of indicating the direction of the reference plane of a well-surveying instrument, for if started rotating say, in a north-and-south plane, the device will continue to maintain itself in this plane as long as rotation continues. A suitable reference marker and a means of recording the position of the gyroscope in its relation with that of a device for measuring the amount of deflection—such as a pendulum—will indicate the direction of the deflection quite independently of the amount of torsion in the supporting pipe or of magnetic influences that may be operative. Among the problems in adapting the gyroscope to this type of work has been the difficulty of making a dependable one small enough for use in a device that can be lowered into an

oil well and of providing for the necessarily rapid rotation of the gyroscope wheel. However, the Sperry Gyroscope Company, after several years of research work, has perfected a new small gyroscopic directional indicator that has been found well adapted to oil-well service and is embodied in the Surwel Clinograph which is to be described in a later section.

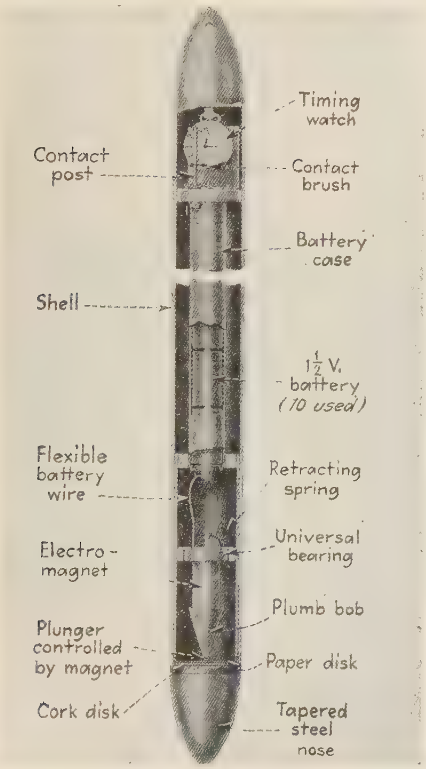
The "Driftmeter."—The Driftmeter utilizes a free-swinging, rigid-arm type of pendulum, suspended on universal bearings above a paper disk, the center of which marks zero deflection (see Fig. 246). Concentric circles about this point mark deflection increments of 1 deg. The instrument is equipped with twelve 1½-volt flash-light dry batteries and a clock which can be set to close an electrical circuit after any desired number of minutes have elapsed—a time sufficient to allow for lowering the instrument to the point in the well where the record is to be made. It may be lowered on the sand line of the cable-tool or combination rig, or on a special measuring line. When the circuit is completed, a small electromagnet, actuated by the dry batteries, raises the record chart, causing a perforating needle on the point of the pendulum to be thrust against the paper disk, thus recording the amount of deflection. For indicating the direction of inclination, a horizontally swinging compass is provided, the compass being automatically clamped in its rest position at the time the record is made by the same mechanism that raises the record chart. The direction of inclination is in the direction of a line drawn through the center of the chart and the needle prick marking the position of the point of the pendulum. The bearing of this line may be determined by reference to the position of the compass needle, since the position of the chart bears a fixed relation to that of the magnetic north point of the compass.

The Alexander Anderson Well-surveying Instrument.—One of the most successful of the well-surveying instruments, widely used in the California fields, is that developed and exploited by Alexander Anderson. Anderson has withheld detailed description of this instrument pending final action on patent applications, but it is reported that it makes use of a group of five independent pendulums of disk type, disposed about the circumference of a ring several inches in diameter, and that mechanism is provided for making photographs on motion-picture film, showing the positions of the pendulums at brief intervals as the device is lowered into the well. Eighty-eight photographs on motion-picture film may be made with one round-trip of the drill pipe, on the lower end of which the instrument is suspended. Computations based upon the deflection of the pendulums permit of determining the inclination of the well at many different depths. One photograph is usually made for each stand of drill pipe lowered into and withdrawn from the well, that is, about 12 readings per thousand feet of depth, or per hour. Deflections can be measured with this instrument up to 60 deg. from the vertical and may be computed to the nearest 10 min. of arc. The direction in which the reference point of the instrument lies is determined by orienting the drill pipe at the surface, and it is claimed that this may be done within a tolerance of about 3 deg.

The Surwel Clinograph.—This device, which has been mentioned in an earlier section as one employing the gyroscope as a direction finder, is illustrated in Fig. 247. The amount of deflection of the well from the vertical is indicated by a box-level gage. The instrument also contains a watch, a dial thermometer, and a special motor-operated camera using 16-mm. motion-picture film. Dry-battery cells provide power for operating the gyroscope, the camera motor and furnish light for making the photographs. The several parts are so arranged that each photograph shows the position of the gyroscope pointer, the level bubble, the thermometer and the watch dial. A series of such photographs, made at different depths in a well, afford a means of accurately and completely charting its course.

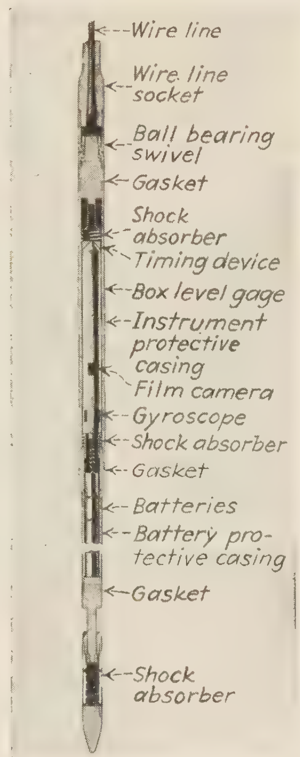
The gyroscope wheel is revolved about its axis by a small motor at from 10,000 to 14,000 r.p.m. and is balanced in such a way that it will maintain its axis in whatever

plane it may be set, for a long period of time. A pointer, mounted over a compass scale, is attached to the gyroscope axis and indicates the direction of the axis of rotation. A non-magnetic watch having three hands shows the time at which photographs are made. A large second hand on the watch makes it possible to read the time to ⅕ sec. The dial thermometer, having a range of from 0 to 240°F., shows the temperature existing inside the protective casing. The camera, located immediately above the gyroscopic unit, has two lenses which record pictures taken in opposite directions simultaneously on the same film. One lens photographs the gyroscope



(*Courtesy of Driftmeter, Inc.*)

FIG. 246.—Sectional view of the "Driftmeter."



(*Courtesy of Sperry-Sun Well Surveying Co.*)

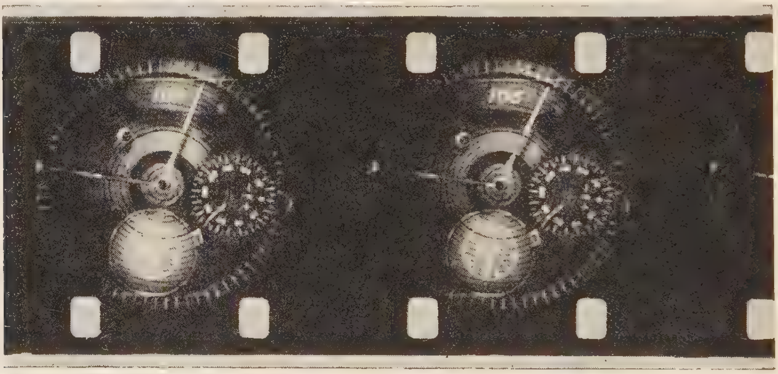
FIG. 247.—Vertical section through Surwel Clinograph.

pointer and compass scale, the watch dial and the thermometer, located below, and the other the position of the bubble in the box-level gage immediately above the camera unit (see Fig. 248). The necessary light for making the photograph is obtained from several incandescent lamps operated by current from the dry cells through an automatic and adjustable contact device synchronizing with the movement of the film. The movement of the film is intermittent; pictures are taken while the film is at rest, at the rate of one picture for each 6 to 8 sec., if the instrument is lowered on a wire line into the well at the rate of about 3 ft. per second. If lowered on a drill stem, a very accurate timing device is arranged on top of the box-level gage. This timing device controls the operation of the camera motor and is so adjusted that one photograph is made for each "fourble" stand of drill pipe lowered. The timing device

is adjustable to vary the time allowance for connecting and lowering the drill pipe from 1¼ to 2½ min. This adjustment will vary with the depth of the well, the equipment available in the derrick and the skill of the crew.

The box-level gage, located above the camera unit, has a spherical upper surface with concentric graduations etched to indicate the vertical deviation in degrees. Three different levels are provided with each instrument having maximum inclinations of 20, 40 and 55 deg., respectively. Both the bottom and top are of transparent glass. The nature of the fluid and size of the bubble are such as to damp oscillations but, at the same time, prevent lag in readjustments of the position of the bubble. The gage is equipped with expansion coils to adjust the volume of the fluid to changes in temperature.

The three units are inserted into a steel protective casing made up in three sections and capable of withstanding outside hydrostatic pressures up to 6,000 lb. per square inch. The lower section is provided with a steel nose and shock absorber and carries the dry-cell batteries, the center section carries the Surwel instrument and the top section is equipped with either a wire-line socket or a sub, depending upon whether the instrument is to be operated on the wire line or on drill pipe.



(*Courtesy of Sperry-Sun Well Surveying Co.*)

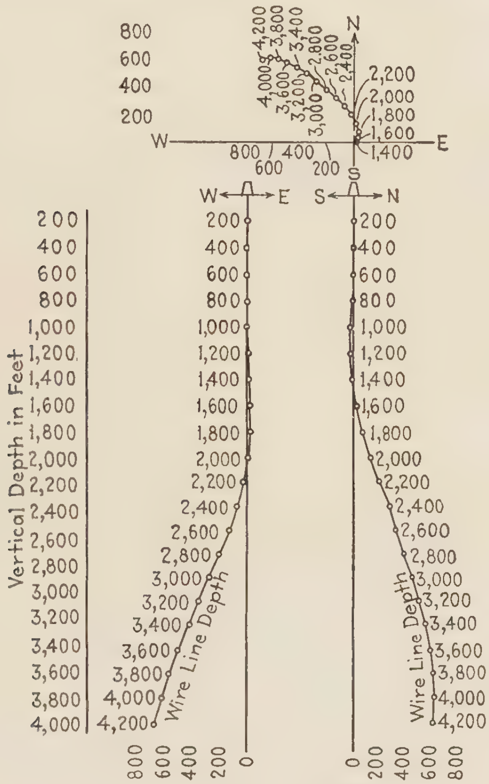
FIG. 248.—Motion-picture film records made by the Surwel Clinograph.

When lowering the instrument, the time is closely observed by the operator on a watch synchronized with that in the instrument, thus fixing the depth at which each photograph is taken. Records are made both while descending and while ascending, and each set of records is interpreted in the direction in which it is taken. This procedure is equivalent to making two surveys, thus providing a check on the accuracy of the work. Upon the return of the instrument to the surface, the film is removed and developed. The photographs show the inclination from the vertical, the orientation as well as the time (indicating the depth) and the temperature. Correction for the cardinal error, parallax and refraction (established for each instrument) are made, and a complete map of the well is then constructed. This map consists of three projections: a vertical projection on a north-south plane, a vertical projection on an east-west plane and a horizontal projection. From these projections, the position of the well at any reference point or plane can be ascertained with respect to the position of the mouth of the well at the surface (see Fig. 249).

The Sperry-Sun Well Surveying Company, which controls the patent rights on this instrument and undertakes the making of well surveys with it, guarantees a resurvey if the closure at the bottom of the well between in and out runs is more than 1 per cent of the depth of the well. Additional advantages are found in speedy operation, freedom from cumulative errors and independence of magnetic conditions or

tortuosity in the course of the well. The service given in the application of this instrument is confidential, the film, all working sheets and the map being given to the owner of the well. If the owner desires to be the only person who knows the results of the survey, he may develop and interpret the records for himself or he may select a direction for the gyro pointer which is known only to him.

Extent of Deviation of Wells from the Vertical.—Some almost unbelievable deflections of rotary-drilled wells have been reported as a result



(Courtesy of Sperry-Sun Well Surveying Co.)

FIG. 249.—Results of a well survey projected on one horizontal and two vertical planes making right angles with each other.

of carefully made surveys with dependable instruments. Inclinations from the vertical as great as 60 or 70 deg. have been noted in some instances. The deflection does not always continue in the same direction. A hole may drift in one direction for a time, then turn in some other direction. It seems difficult to conceive of the heavy drill pipe operating successfully in wells having such deflections, but when it is considered that the pipe is like a column, partly under tension and partly under compression, the length of which is many thousand times its diameter, it is realized that, as a whole, it may be quite a flexible unit.

A survey of a 5,100-ft. well, drilled by the rotary method in the Seminole District of Oklahoma, indicated that it had drifted horizontally 2,470 ft. from the starting point and that some 800 ft. of excess hole had been drilled beyond what would have been necessary to reach a comparable depth in a vertical well. One well drilled in a California field was found to have an inclination of 56 deg. from the vertical at a measured depth of 5,683 ft. The vertical depth to this point was only 4,893 ft., which is 790 ft. less than the measured depth, and the horizontal displacement was 2,252 ft. Though drilling was continued in this well to a

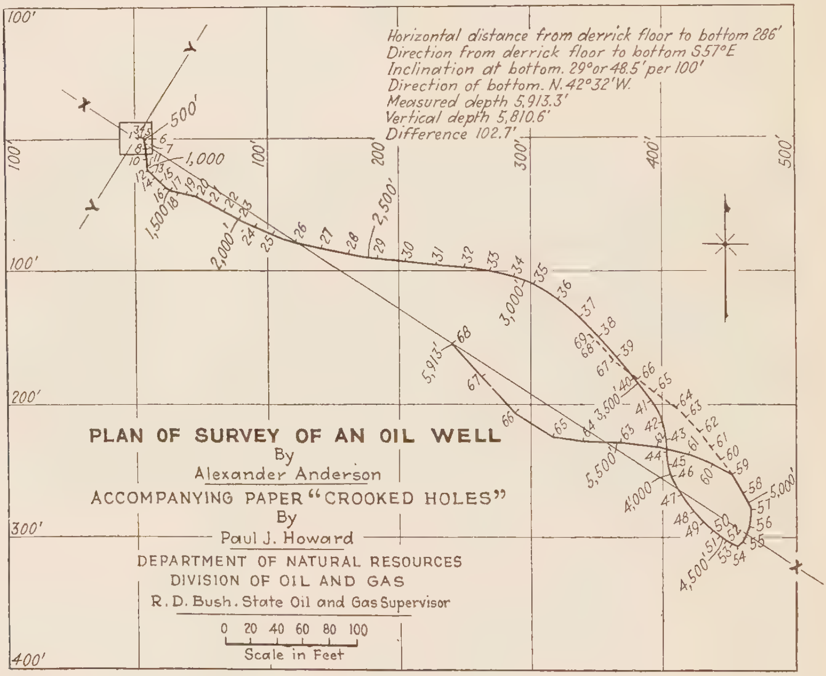


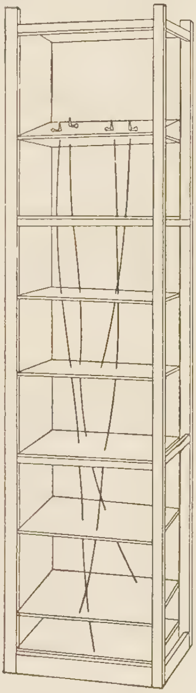
Fig. 250.—Horizontal plat of a well that followed an unusually erratic course.

depth of 6,410 ft., no unusual mechanical difficulties of any sort were experienced and there were no twist-offs of the drill pipe. These, no doubt, are extreme cases, but the results of 38 surveys of rotary-drilled wells in the California oil fields, drilled to depths in excess of 6,000 ft., show an average drift from the vertical of 132 ft. per 1,000 ft. of depth and an average inclination from the vertical of 22 deg. The magnitude of the deflection often increases with depth. That this tendency of wells to become crooked is not characteristic of rotary-drilled wells exclusively is shown by surveys of deep wells drilled with cable tools in Pennsylvania. Here deviations of as much as 50 ft. per hundred have been recorded in some instances. At a depth of 7,550 ft., one well had an inclination of 27 deg. from the vertical. Most well-surveying instruments are not

designed for measuring extreme deflections so that there are cases where the holes become so flat as to be unmeasurable.[21]

Realizing the importance of avoiding extreme deflections, some operators survey their wells at intervals during drilling, and whenever the deflection exceeds a small amount, say 5 deg., require that appropriate measures be taken to straighten the hole. This practice is prescribed by the Railroad Commission of Texas in its regulations governing administration of the state's oil conservation laws. The operator is, in most cases, not greatly concerned over the direction of the deflection if the amount of the deviation does not exceed 5 deg., and for such surveys as are necessary to determine this acid bottles or simple types of clinographs will be found sufficiently accurate.

Methods of Presenting Results of Well Surveys.—A complete representation of the course of a well is afforded by projecting its position on three reference planes making right angles with each other. One of these should be a horizontal plane. The other two may be north-south and east-west planes, or the two vertical planes may be oriented in such a manner as will best display the true inclination from the vertical. Figure 249 presents a typical projection on three planes. Figure 250 is a plan view of a well which followed an unusually erratic course. A realistic method of displaying the course of a well is illustrated in Fig. 251. This is essentially a three-dimensional model. Copper wire, bent to conform to the actual course of the well, is used to represent each of the four wells pictured. Horizontally placed screens may be used to mark the major reference horizons. A convenient scale for such a model is 100 ft. per inch.



(*After M. Van Couvering in Bull., Am. Assoc. Petroleum Geol.*)

FIG. 251.—Three-dimensional model illustrating courses of oil-well drill holes.

GRAPHIC METHODS OF RECORDING FIELD DATA

Field Maps.—Field maps are constructed by first drawing a map of the property lines, together with the railroads, highways, town sites and other permanent improvements, in as much detail as desired or as the scale of the map will permit. Ownership of various properties, section and township lines and numbers are also carefully lettered. Using this base map as a frame, all wells are then located to scale with reference to property lines or section corners. The position of each well is indicated by a small circle, using conventional symbols (see Fig. 252) in connection therewith, to indicate whether the well is a drilling well, a producing oil well, a gas well, a dry hole, a well abandoned in process of drilling, a well

temporarily idle or an abandoned producer. The number of the well, or the name by which it is known, is lettered at one side of the symbol marking its position, and, if the scale of the map permits, the elevation of the derrick floor and the depth of the well may also be indicated; and perhaps, also, the initial production.

Figure 253 illustrates a typical field map. It is obvious that to serve its intended purpose, which is primarily to show in a broad way the extent of development in different portions of the field, the map must be of rather small scale, otherwise it becomes unwieldy. Scales of 2,000 or 1,000 ft. to the inch are commonly used for this type of map. These are large enough to permit of showing the positions of the wells, their numbers, names of property owners, etc., but do not allow space for much further detail.

Property Maps.—Maps of larger scale, often 200 or 300 ft. to the inch, afford opportunity for indicating the position of wells, derricks and rigs, buildings, tanks and reservoirs, pipe lines, roads, telephone lines,

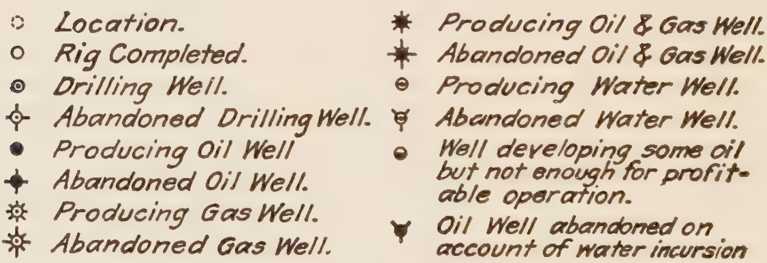


Fig. 252.—Conventional symbols for oil field maps.

fences and other structures in full detail. Such maps are called "property maps" to distinguish them from the smaller scale field maps. The map shown in Fig. 254 is typical.

Vertical sections on which the structural and stratigraphical features may be displayed to good advantage are conveniently constructed with the aid of graphic logs prepared as described in an earlier section. Cross sections developed in this way are most useful in studying the underground conditions in oil fields. The formations are determined by the drilling records, and the cross sections are used to correlate these formations from well to well. Even in a region of simple geologic structure and stratigraphy, cross sections are necessary to bring out the local variations in structure. Irregularities of well depths and casing depths can also be studied to advantage with the aid of cross sections. They form, in fact, the basis of the work of the engineer and geologist in studying underground losses and methods of improving recovery.

The selection of the position of the cross section involves choosing a line of wells that will give sufficient information and that lies in the desired position with respect to the axes of the structure. Usually, it is desirable to have one or more cross sec-

tions plotted at right angles to the major axis of the structure and one parallel with the major axis. To aid in correlating, it is particularly desirable to have one or both end wells of each cross section overlap, that is, the log of the end well should also be

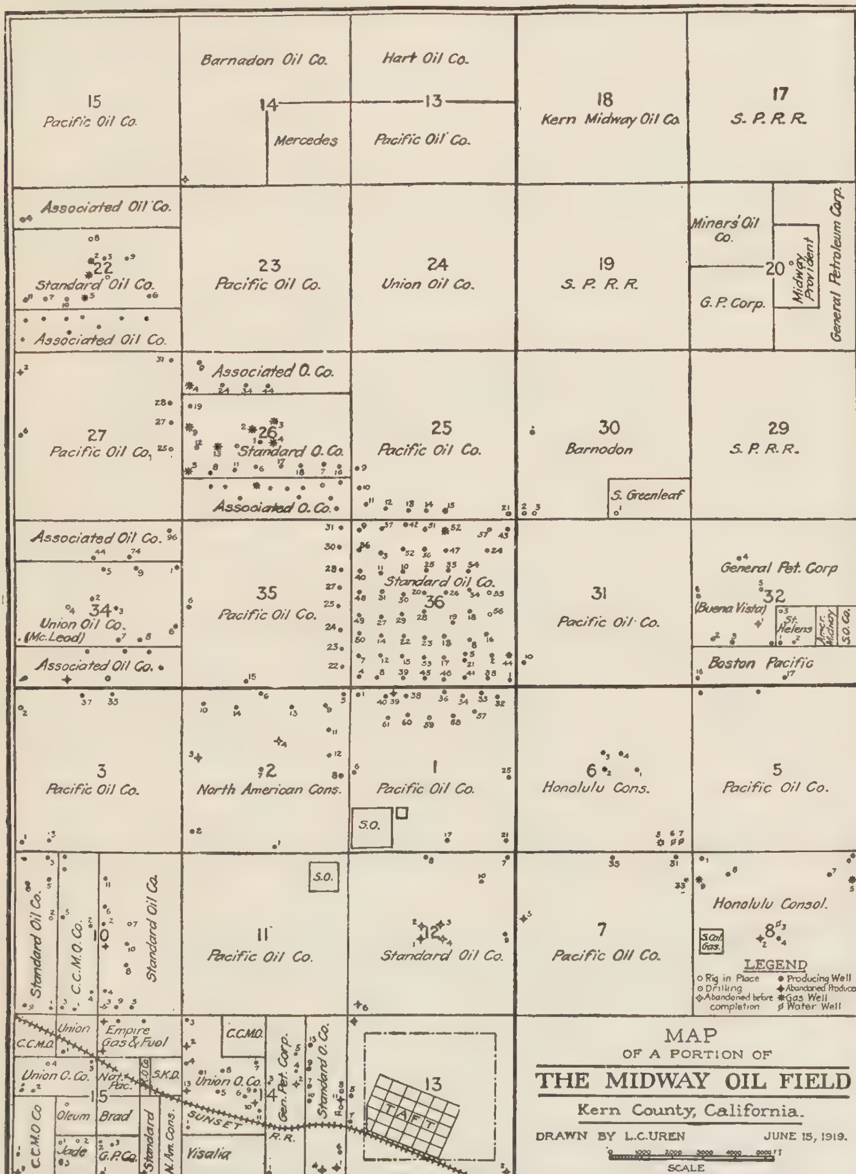


FIG. 253.—A typical field map.

plotted on some other cross section. The graphic log of every well on a property should be plotted on at least one cross section. If it happens that a particular well falls a little to one side of a desired cross section, it is often possible to project it into

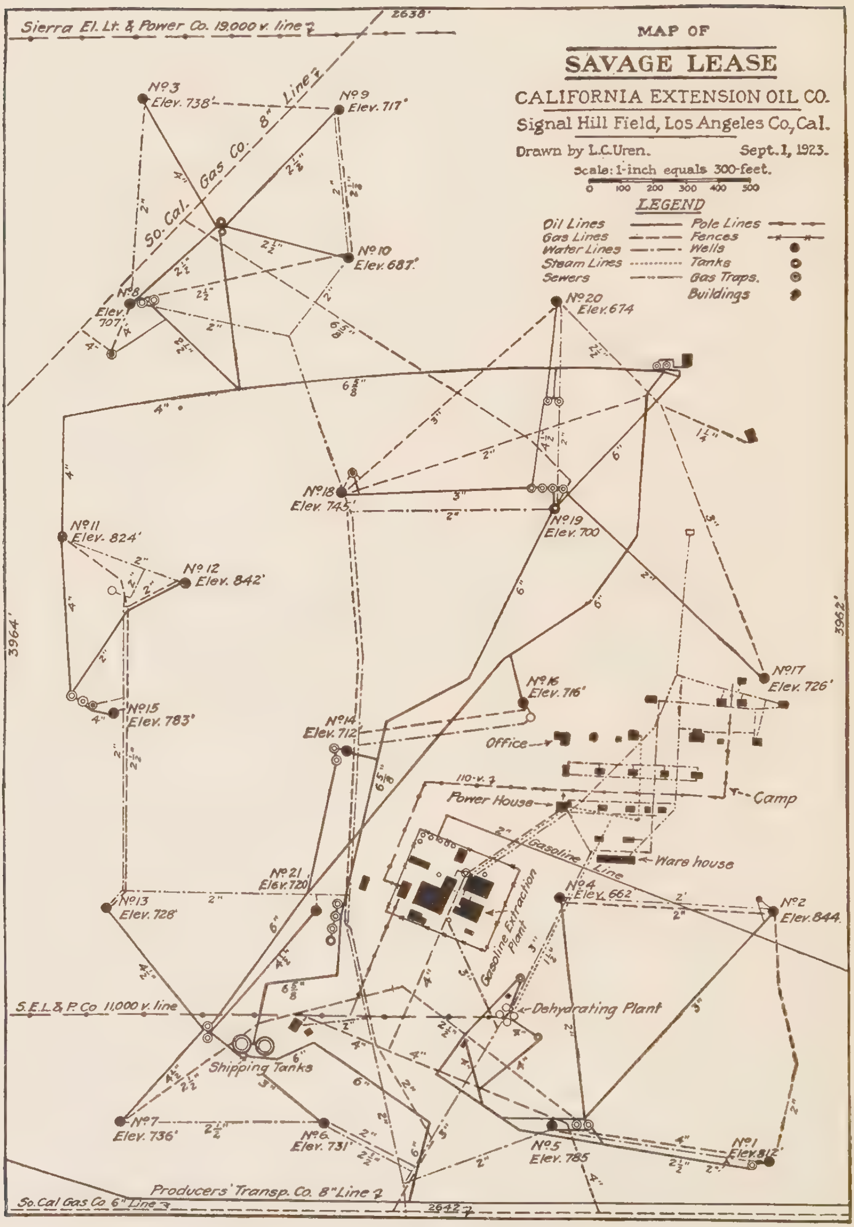
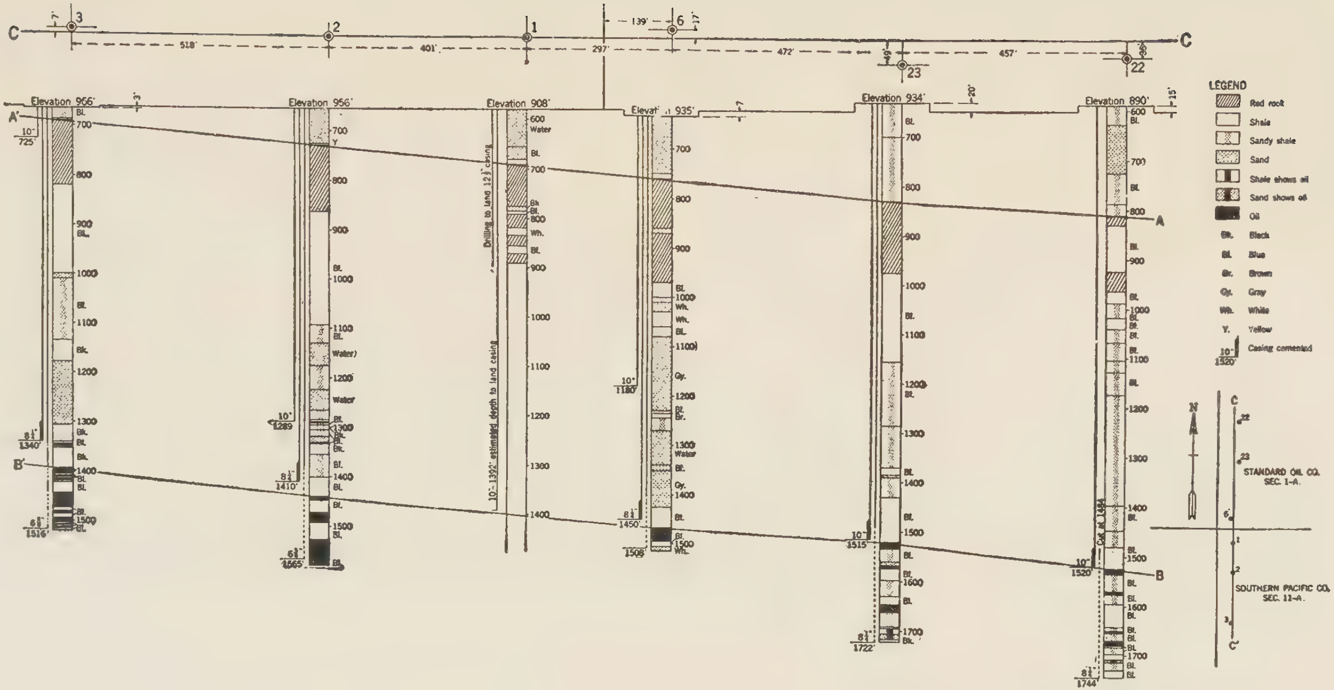


FIG. 254.—A typical property map.

The property is only partially developed. Wells produce both oil and gas and are operated by individual gas engines. Buildings may be conveniently numbered, with reference to a list giving purpose and dimensions of each.



(After R. E. Collom in U. S. Bur. Mines, Bull. 201.)

Fig. 255.—Illustrating development of geologic sections by correlation of well logs. Lines A-A′ and B-B′ represent correlations of marker horizons.

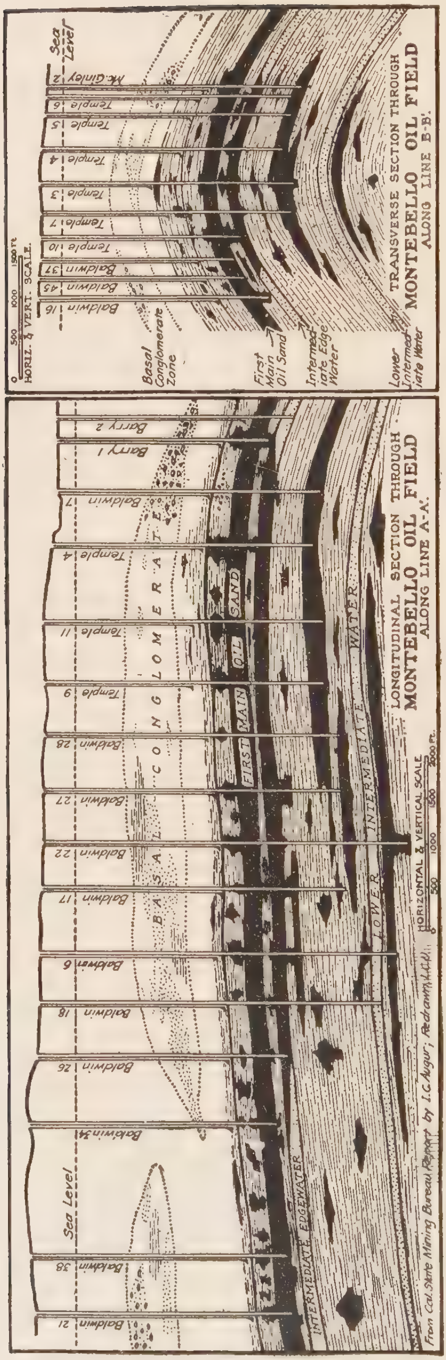


FIG. 256.—Typical geologic sections developed from well log data.
Note position of these sections on structure contour map reproduced in Fig. 257.

the plane of the cross section by reference to known marker horizons, or by an actual calculation of equivalent positions with respect to the known dip of the formation. The individual logs may also be correlated by reference to an assumed datum line, such as sea level (see Fig. 255).

There are two general methods of preparing cross sections: one in which the graphic well logs are plotted on a single piece of tracing cloth, properly spaced apart to the scale selected; and the other where the graphic logs are plotted separately on strips of tracing cloth and are arranged at proper distances apart to form the desired cross section. In the latter plan, each graphic log has to be plotted only once, serving in turn for as many different cross sections as may be desired.

Most engineers prefer to construct vertical sections by blueprinting from the graphic log tracings. The graphic log tracings are placed in the printing frame, properly spaced apart on an assumed horizontal scale and adjusted with respect to an assumed datum line. For convenience, we may have a horizontal line ruled on the glass against which the print is made and adjust the sea-level points of all tracings so that they fall on this line. This automatically accounts for differences in elevation of the derrick floors. We may also have marks along the top and bottom of our blueprint frame to serve as a scale, which aids in spacing the logs at the proper distances apart and in keeping them in a vertical position. With a series of logs arranged in the frame in this way, a blueprint is made on one sheet of paper which becomes a permanent copy of the logs as arranged. This print may be later used in developing a completed section.

In order that lines may be drawn on this section, it is desirable to use a positive or blue-line print, which, of course, necessitates making a brown-process negative. Corresponding horizons on different wells in the cross section are first connected with straight lines, and the intervening space between logs may then be worked up in full geologic detail if desired. The appearance is greatly improved by the use of crayon or water color applied in such a way as to develop suitable distinctions between the different strata.

Instead of blueprinting sections in this manner, we may photograph the well logs after properly arranging them to form the desired section. The photostat, a device for making photographic prints directly on bromide paper, is most useful for making the prints if this plan is followed. The photographic prints are then used as a base on which to develop the complete geologic detail if desired.

The cross section should show the number of each well in the section, its elevation, production data, etc., and there should be a supplementary key map indicating the line of the cross section. Every cross section should also have a suitable title (see Fig. 256).

Underground Structure Contour Maps.—Well logs are also useful in constructing what is called an underground structure contour map. Such a map shows by means of contours connecting points of equal elevation, the position and form of an unexposed bed such as the top of an oil sand, over a large area.

Before starting work on a structure contour map, the datum plane must be chosen—this is usually sea level. The contour interval must also be decided upon, and this usually depends upon the nature of the structure, its dip, the data available, the scale adopted and the purpose for which the map is to be used. The contour interval, or distance between successive contours, is frequently 25 or 50 ft.

By a study of well logs or cross sections, the distance between the bed to be contoured and the datum plane is computed for each well and written down beside the well's position on the map. Interpolation between known points determines the elevations of other points. Contours are then sketched in at regular intervals with respect to the elevations so determined (see Fig. 257).

The chief value of such a map is to display broad structural features over a large area in a way not equalled by even the most careful study of geologic cross sections. An underground structure contour map can often be used to show the location of wells relative to folds in the formation, or the most favorable undrilled tracts for the production of oil and gas, and it may be used as an aid in the selecting of well sites. It is also possible with a carefully prepared structure contour map to predict with fair certainty the necessary depth of a well to be drilled at any designated point to intersect the oil sand. The map also serves to indicate the direction and amount of dip of the structure at any point.

Convergence Maps.—Still another type of map that is useful in some ways, and that can be developed from well-log data, is the convergence map. This type of map indicates, by means of contours, the

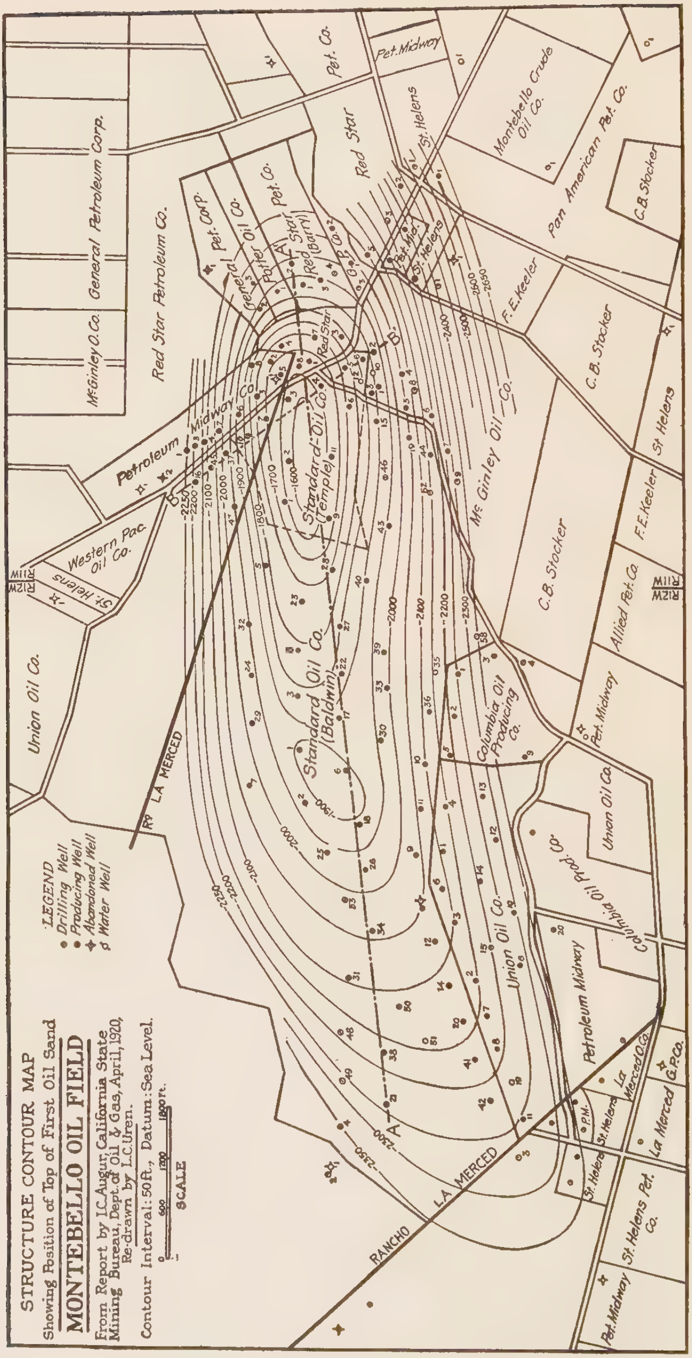


FIG. 257.—A typical structure contour map developed from well log data. Note that vertical sections along lines *A-A'* and *B-B'* are reproduced in Fig. 256.

difference in elevation at any point between two irregular and non-parallel horizons. It may show, for example, the difference in elevation between the surface of the earth and the top of a submerged oil sand. The convergence map is constructed in much the same manner as the structure contour map, calculating the distance between the two horizons at various points from the known rate of convergence and connecting points having the same difference in elevation with contour lines.

Peg Models.—The most satisfactory method of demonstrating the structural conditions disclosed by a series of well logs is by constructing what is called a "peg model." Peg models have a great advantage over maps and sections in that they present the data directly in three dimensions instead of two, so that we obtain an actual picture of the situation. The method has been found especially useful to the non-technical man, who grasps readily the essentials from a model, whereas cross sections and contour maps are apt to be confusing.

Peg models are widely used in making correlations of structure between one well and a group of others and are especially useful in determining the proper points at which to cement off water in a drilling well, in predicting the position of oil, gas and water sands, the proper position for casing perforations, casing depths, etc. Any marked irregularities in well depths are brought out at once by inspection of such a model.

A peg model is easily made.* First a baseboard of suitable size must be prepared. The baseboard should be made with mortised ends so that it will not warp, should be planed smooth on top and should be about 1½ in. thick. It is customary to cut the baseboards so that they represent, according to some assumed scale, the area of a section or quarter section of land. The scale used is often 100 ft. to the inch. The well locations and property lines, names of property owners, etc., are then carefully scaled off and indicated on the baseboard, developing what is in effect a rough map of the area represented.

At each well location a hole is drilled with a drill press to a uniform depth, usually about 1 in. Care must be taken in boring these holes that they are absolutely vertical, otherwise the pegs will not stand vertically above the board. The pegs used may be of seasoned pine, about ½ in. in diameter. All pegs should be of the same diameter and length. These pegs or dowels can be turned out by any planing mill at reasonable cost.

A blueprint of a graphic log, drawn on a scale of 100 ft. to the inch, is then cut just wide enough to wrap around the peg and is glued on to the peg. The logs should be mounted on the pegs so that the sea-level, or datum, line, in each case lies in the same horizontal plane or at the same distance from the lower end of the peg. To accomplish this, the pegs are marked a certain distance from the baseboard, and the sea-level line, or other datum line of the log, is glued opposite that mark. The datum plane thus established should be far enough above the baseboard to allow the deepest wells to be shown to their full depths. The pegs should be long enough to show all formations penetrated by the well with the highest surface elevation.

* Case, J. B., and H. B. Thompson: Peg Models: Their Construction and Use, *Summary of Operations, California Oil Fields*, May, 1921, pp. 5–21. Sixth annual report of the California State Oil and Gas Supervisor.

The pegs representing different wells are then placed in their corresponding holes in the baseboard, and the principal oil or water sands are correlated by means of bright-colored threads running from peg to peg. Usually, also, one definite marker is shown by means of a certain colored string. Push pins with colored enameled heads may be used to advantage on the pegs, to indicate water shut-offs and other important features of the work (see Fig. 258).

One of the larger oil companies uses small aluminum or steel rods (¼ in.) instead of wooden pegs, and the formations are painted on the rods with the aid of a lathe.

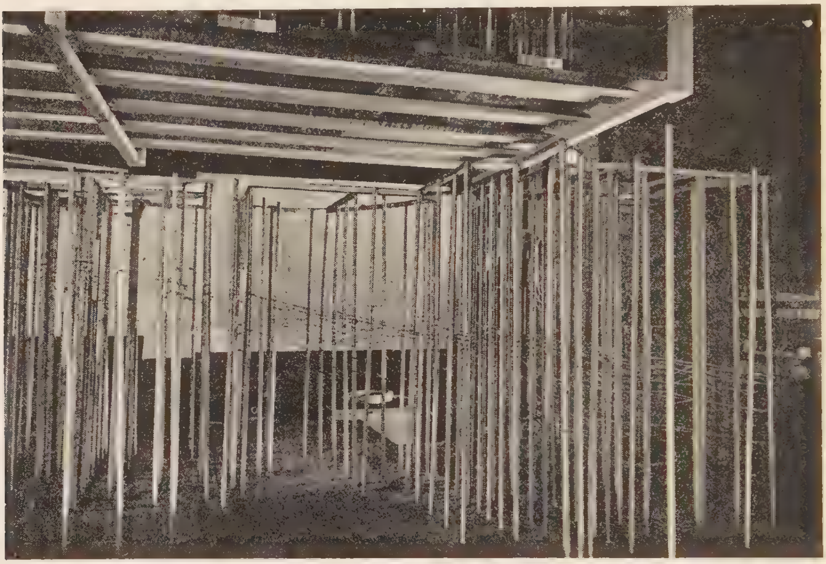


FIG. 258.—A typical peg model.

Others use glass tubes about ¾ in. in diameter instead of pegs, the tubes being filled to appropriate depths with carefully washed drill cuttings from the various formations penetrated. A paper strip log may be glued on the outer surface of each glass tube in such a way as to leave part of the glass clear for observation of the drill cuttings.

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AUTHOR INDEX

(List of authors referred to in the text and bibliographies)

SUBJECT INDEX

C

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